PROGRESS ENERGY INC

FORM 10-K
(Annual Report)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number	Exact name of registrants as specified in their charters, state of incorporation, address of principal executive offices, and telephone number	I.R.S. Employer Identification Number
1-15929	**Progress Energy, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-2155481
1-3382	**Carolina Power & Light Company** **d/b/a Progress Energy Carolinas, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-0165465
1-3274	**Florida Power Corporation** **d/b/a Progress Energy Florida, Inc.** 299 First Avenue North St. Petersburg, Florida 33701 Telephone: (727) 820-5151 State of Incorporation: Florida	59-0247770

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Progress Energy, Inc.:	
Common Stock (Without Par Value)	New York Stock Exchange
Carolina Power & Light Company:	None
Florida Power Corporation:	None

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Progress Energy, Inc.:	None
Carolina Power & Light Company:	$5 Preferred Stock, No Par Value Serial Preferred Stock, No Par Value
Florida Power Corporation:	None

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Act **.**

Progress Energy, Inc. (Progress Energy)	Yes	(X)	No	( )
Carolina Power & Light Company (PEC)	Yes	( )	No	(X)
Florida Power Corporation (PEF)	Yes	( )	No	(X)

Indicate by check mark whether each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Progress Energy	Yes	( )	No	(X)
PEC	Yes	( )	No	(X)
PEF	Yes	(X)	No	( )

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Progress Energy	Yes	(X)	No	( )
PEC	Yes	(X)	No	( )
PEF	Yes	( )	No	(X)

Indicate by check mark whether each registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

Progress Energy	Yes	(X)	No	( )
PEC	Yes	( )	No	( )
PEF	Yes	( )	No	( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in PART III of this Form 10-K or any amendment to this Form 10-K.

Progress Energy	(X)
PEC	(X)
PEF	(X)

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act:

Progress Energy	Large accelerated filer	(X)	Accelerated filer	( )
	Non-accelerated filer	( )	Smaller reporting company	( )
PEC	Large accelerated filer	( )	Accelerated filer	( )
	Non-accelerated filer	(X)	Smaller reporting company	( )
PEF	Large accelerated filer	( )	Accelerated filer	( )
	Non-accelerated filer	(X)	Smaller reporting company	( )

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Act).

Progress Energy	Yes	( )	No	(X)
PEC	Yes	( )	No	(X)
PEF	Yes	( )	No	(X)

As of June 30, 2009, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $10,535,128,179. As of June 30, 2009, the aggregate market value of the common equity of PEC held by nonaffiliates was $0. All of the common stock of PEC is owned by Progress Energy. As of June 30, 2009, the aggregate market value of the common equity of PEF held by nonaffiliates was $0. All of the common stock of PEF is indirectly owned by Progress Energy.

As of February 22 , 2010, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	284,621,114
PEC	Common Stock (Without Par Value)	159,608,055
PEF	Common Stock (Without Par Value)	100

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Progress Energy and PEC definitive proxy statements for the 2010 Annual Meeting of Shareholders are incorporated into PART III, Items 10, 11, 12 , 13 and 14 hereof.

This combined Form 10-K is filed separately by three registrants: Progress Energy, PEC and PEF (collectively, the Progress Registrants). Information contained herein relating to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrants.

PEF meets the conditions set forth in General Instruction I (1) (a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format permitted by General Instruction I (2) to such Form 10-K.

TABLE OF CONTENTS

GLOSSARY OF TERMS

We use the words "Progress Energy," "we," "us" or "our" with respect to certain information to indicate that such information relates to Progress Energy, Inc. and its subsidiaries on a consolidated basis. When appropriate, the parent holding company or the subsidiaries of Progress Energy are specifically identified on an unconsolidated basis as we discuss their various business activities.

The following abbreviations, acronyms or initialisms are used by the Progress Registrants:

TERM	DEFINITION
401(k)	Progress Energy 401(k) Savings & Stock Ownership Plan
AFUDC	Allowance for funds used during construction
ARB	Accounting Research Bulletin
ARO	Asset retirement obligation
ASLB	Atomic Safety and Licensing Board
Asset Purchase Agreement	Agreement by and among Global, Earthco and certain affiliates, and the Progress Affiliates as amended on August 23, 2000
ASC	FASB Accounting Standards Codification
ASU	Accounting Standards Update
Audit Committee	Audit and Corporate Performance Committee of Progress Energy's board of directors
BART	Best Available Retrofit Technology
Base Revenues	Non-GAAP measure defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues
Brunswick	PEC's Brunswick Nuclear Plant
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCO	Competitive Commercial Operations
CCRC	Capacity Cost-Recovery Clause
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Ceredo	Ceredo Synfuel LLC
CIGFUR	Carolina Industrial Group for Fair Utility Rates II
Clean Smokestacks Act	North Carolina Clean Smokestacks Act, enacted in June 2002
Coal Mining	Two Progress Fuels subsidiaries engaged in the coal mining business, which were sold on March 7, 2008
the Code	Internal Revenue Code
CO_2	Carbon dioxide
COL	Combined license
Corporate and Other	Corporate and Other segment primarily includes the Parent, Progress Energy Service Company and miscellaneous other nonregulated businesses
CR1 and CR2	PEF's Crystal River Units No. 1 and 2 coal-fired steam turbines
CR3	PEF's Crystal River Unit No. 3 Nuclear Plant
CR4 and CR5	PEF's Crystal River Units No. 4 and 5 coal-fired steam turbines
CUCA	Carolina Utility Customer Association
CVO	Contingent value obligation
D.C. Court of Appeals	U.S. Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DSM	Demand-side management
Earthco	Four coal-based solid synthetic fuels limited liability companies of which three were wholly owned
ECCR	Energy Conservation Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause

EIP	Equity Incentive Plan
EPACT	Energy Policy Act of 2005
EPC	Engineering, procurement and construction
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
Fitch	Fitch Ratings
the Florida Global Case	U.S. Global, LLC v. Progress Energy, Inc. et al
Florida Progress	Florida Progress Corporation
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
Funding Corp.	Florida Progress Funding Corporation, a wholly owned subsidiary of Florida Progress
GAAP	Accounting principles generally accepted in the United States of America
the Georgia Contracts	Full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO
Georgia Operations	Former reporting unit consisting of the Effingham, Monroe, Walton and Washington nonregulated generation plants in service and the Georgia Contracts
GHG	Greenhouse gas
Global	U.S. Global, LLC
GridSouth	GridSouth Transco, LLC
GWh	Gigawatts-hours
Harris	PEC's Shearon Harris Nuclear Plant
IPP	Progress Energy Investor Plus Plan
kV	Kilovolt
kVA	Kilovolt-ampere
kWh	Kilowatt-hours
Levy	PEF's proposed nuclear plant in Levy County, Fla.
LIBOR	London Inter Bank Offered Rate
MACT	Maximum achievable control technology
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations contained in PART II, Item 7 of this Form 10-K
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured gas plant
MW	Megawatts
MWh	Megawatt-hours
Moody's	Moody's Investors Service, Inc.
NAAQS	National Ambient Air Quality Standards
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCUC	North Carolina Utilities Commission
NDT	Nuclear decommissioning trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
North Carolina Global Case	Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC
the Notes Guarantee	Florida Progress' full and unconditional guarantee of the Subordinated Notes
NOx	Nitrogen Oxides
NOx SIP Call	EPA NOx State Implementation Plan Call rule which requires 22 states including North Carolina, South Carolina and Georgia (but excluding Florida) to further reduce emissions of nitrogen oxides
NRC	United States Nuclear Regulatory Commission
O&M	Operation and maintenance expense
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income

Ongoing Earnings	Non-GAAP financial measure that includes results from continuing operations after excluding the effects of certain identified gains and charges
OPC	Florida's Office of Public Counsel
OPEB	Postretirement benefits other than pensions
the Parent	Progress Energy, Inc. holding company on an unconsolidated basis
PEC	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
PEF	Florida Power Corporation d/b/a Progress Energy Florida, Inc.
PESC	Progress Energy Service Company, LLC
Power Agency	North Carolina Eastern Municipal Power Agency
Preferred Securities	7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A issued by the Trust
Preferred Securities Guarantee	Florida Progress' guarantee of all distributions related to the Preferred Securities
Progress Affiliates	Five affiliated coal-based solid synthetic fuels facilities
Progress Energy	Progress Energy, Inc. and subsidiaries on a consolidated basis
Progress Registrants	The reporting registrants within the Progress Energy consolidated group. Collectively, Progress Energy, Inc., PEC and PEF
Progress Fuels	Progress Fuels Corporation, formerly Electric Fuels Corporation
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PUHCA 2005	Public Utility Holding Company Act of 2005
PVI	Progress Energy Ventures, Inc., formerly referred to as Progress Ventures, Inc.
QF	Qualifying facility
RCA	Revolving credit agreement
Reagents	Commodities such as ammonia and limestone used in emissions control technologies
REPS	Renewable energy portfolio standard
Robinson	PEC's Robinson Nuclear Plant
RSU	Restricted stock unit
RTO	Regional transmission organization
SCPSC	Public Service Commission of South Carolina
Section 29	Section 29 of the Code
Section 29/45K	General business tax credits earned after December 31, 2005 for synthetic fuels production in accordance with Section 29
Section 316(b)	Section 316(b) of the Clean Water Act
(See Note/s "#")	For all sections, this is a cross-reference to the Combined Notes to the Financial Statements contained in PART II, Item 8 of this Form 10-K
SERC	SERC Reliability Corporation
S&P	Standard & Poor's Rating Services
SNG	Southern Natural Gas Company
SO_2	Sulfur dioxide
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
Terminals	Coal terminals and docks in West Virginia and Kentucky, which were sold on March 7, 2008
the Trust	FPC Capital I
the Utilities	Collectively, PEC and PEF
VIE	Variable interest entity
Ward	Ward Transformer site located in Raleigh, N.C.
Ward OU1	Operable unit for stream segments downstream from the Ward site
Ward OU2	Operable unit for further investigation at the Ward facility and certain adjacent areas

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

In this combined report, each of the Progress Registrants makes forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The matters discussed throughout this combined Form 10-K that are not historical facts are forward looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Any forward-looking statement is based on information current as of the date of this report and speaks only as of the date on which such statement is made, and the Progress Registrants undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

In addition, examples of forward-looking statements discussed in this Form 10-K include, but are not limited to, 1) statements made in PART I, Item 1A, “Risk Factors” and 2) PART II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (MD&A) including, but not limited to, statements under the following headings: a) “Strategy” about our future strategy and goals; b) “Results of Operations” about trends and uncertainties; c) “Liquidity and Capital Resources” about operating cash flows, future liquidity requirements and estimated capital expenditures through the year 2012; and d) “Other Matters” about the effects of new environmental regulations, changes in the regulatory environment, meeting anticipated demand in our regulated service territories, potential nuclear construction and our synthetic fuels tax credits.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and energy policy; our ability to recover eligible costs and earn an adequate return on investment through the regulatory process; the ability to successfully operate electric generating facilities and deliver electricity to customers; the impact on our facilities and businesses from a terrorist attack; the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation and potential construction of nuclear facilities, including environmental, health, regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and regulations; risks associated with climate change; weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; the Progress Registrants’ ability to control costs, including operations and maintenance expense (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to Progress Energy, Inc. holding company (the Parent); current economic conditions; the ability to successfully access capital markets on favorable terms; the stability of commercial credit markets and our access to short- and long-term credit; the impact that increases in leverage or reductions in cash flow may have on each of the Progress Registrants; the Progress Registrants’ ability to maintain their current credit ratings and the impacts in the event their credit ratings are downgraded; the investment performance of our nuclear decommissioning trust (NDT) funds; the investment performance of the assets of our pension and benefit plans and resulting impact on future funding requirements; the impact of potential goodwill impairments; our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); and the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in the Progress Registrants’ filings with the SEC. Many, but not all, of the factors that may impact actual results are discussed in Item 1A, “Risk Factors,” which you should carefully read. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can management assess the effect of each such factor on the Progress Registrants.

PART I

ITEM 1. BUSINESS

GENERAL

ORGANIZATION

Progress Energy, Inc. is a public utility holding company primarily engaged in the regulated electric utility business. Headquartered in Raleigh, N.C., it owns, directly or indirectly, all of the outstanding common stock of its utility subsidiaries and varying percentages of other nonregulated subsidiaries. As discussed in Note 3, most nonregulated business operations have been divested in recent years. In this report, Progress Energy, which includes the Parent and its subsidiaries on a consolidated basis, is at times referred to as "we," "our" or "us." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. However, neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself. The Parent was incorporated on August 19, 1999, initially as CP&L Energy, Inc. and became the holding company for PEC on June 19, 2000. We acquired PEF through our November 2000 acquisition of its parent, Florida Progress Corporation (Florida Progress).

As a registered holding company, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005 (PUHCA 2005). Included within its broad authority, the FERC's approval is required prior to any merger involving a public utility and prior to the disposition of any utility asset with a market value in excess of $10 million. The FERC prohibits market participants from intentionally or recklessly making any fraudulent or misleading statements with regard to transactions subject to the FERC's jurisdiction.

Our reportable segments are PEC and PEF, which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 19 for information regarding the revenues, income and assets attributable to our business segments.

The Utilities have more than 22,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. The Utilities operate in retail service territories that have historically had population growth higher than the U.S. average. However, like other parts of the United States, our service territories and business have been negatively impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. PEC's greater proportion of commercial and industrial customers, combined with PEF's greater proportion of residential customers, creates a balanced customer base. We are dedicated to meeting the growth needs of our service territories and delivering reliable, competitively priced energy from a diverse portfolio of power plants.

For the year ended December 31, 2009, our consolidated revenues were $9.885 billion and our consolidated assets at year-end were $31.236 billion.

RECENT DEVELOPMENTS

In 2009, we concentrated on strategies to address current economic conditions and the ongoing public policy debate on energy and the environment. We continued our efforts toward implementing our balanced solution strategy of energy efficiency, alternative energy and state-of-the-art power generation. The utility industry as a whole faces significant cost pressures and lower retail energy sales. We focused on continuous business excellence, cost management and operational efficiency to help offset lower energy sales at the Utilities.

In 2009, PEF successfully sought and received interim and limited rate relief and nuclear cost recovery in Florida. However, in January 2010, in response to a base rate case PEF filed with the Florida Public Service Commission (FPSC) in 2009, the FPSC voted to grant PEF no increase in base rates above the approximately $132 million annual revenue requirement that had been previously awarded in 2009 as limited rate relief for the repowered Bartow Plant. We believe the PEF revenue level approved is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF's right by law to a reasonable opportunity to recover its operating costs and return on invested capital. Consequently, we are currently reviewing our regulatory options in Florida. As a result of the FPSC's decision, Fitch Ratings, Moody's Investors Services, Inc. and Standard and Poor's Rating Services have indicated that they believe the risk related to Florida's regulatory environment has increased. This perceived increased risk, along with the revenue requirements level approved in the FPSC decision, has caused the rating agencies to put certain credit ratings of PEF, and in some cases the Parent and PEC, on negative watch. See MD&A – "Liquidity and Capital Resources – Credit Rating Matters" for additional information regarding our credit ratings.

While we have not made a final determination on nuclear construction, in 2009 we continued to take steps to keep open the option of building a plant or plants at Shearon Harris Nuclear Plant (Harris) in North Carolina and at a greenfield site in Levy County, Florida (Levy). We have focused on Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce greenhouse gas (GHG) emissions, as well as existing state legislative policy, which is supportive of nuclear projects. PEF has received two of the three key approvals (with the issuance of a combined license (COL) by the United States Nuclear Regulatory Commission (NRC) remaining) and entered into an engineering, procurement and construction (EPC) agreement for the two proposed Levy units. In 2009, the NRC indicated it would process PEF's limited work authorization request following COL issuance. This resulted in a minimum 20-month in-service schedule shift for the Levy units. As discussed in "Nuclear Matters – Potential New Construction," additional schedule shifts are likely. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan regarding Levy.

During 2009, there were a number of state and federal initiatives related to energy and environmental policy. With the state, federal and international focus on global climate change, we are preparing for a carbon-constrained future. We are expanding and enhancing our demand-side management (DSM), energy-efficiency and energy conservation programs. We continue to actively pursue alternative energy projects. We have executed contracts to purchase approximately 320 MW of electricity generated from solar, biomass and municipal solid waste sources. We announced our intention to embark on a major coal-to-gas fleet modernization in North Carolina by retiring approximately 1,500 MW of older coal-fired units by the end of 2017 and building combined-cycle gas. This will provide rate base growth while reducing our carbon emissions. We also placed into service pollution control equipment (or scrubbers) on PEC's Mayo Plant and PEF's Crystal River Unit No. 5 (CR5). Additionally, we were notified of our selection for grant negotiations under The American Recovery and Reinvestment Act's Smart Grid technology development grant program. The submission of an application and the notification for award negotiations are not a commitment to accept federal funds but are necessary steps to keep the option open. We are currently evaluating the provisions of the law and assessing the conditions imposed by participation in the grant program.

AVAILABLE INFORMATION

The Progress Registrants' annual reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available free of charge through the Investors section of our Web site at www.progress-energy.com. These reports are available as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. The public may read and copy any material we have filed with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information regarding the operations of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. Alternatively, the SEC maintains a Web site, www.sec.gov, containing reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

The Investors section of our Web site also includes our corporate governance guidelines and code of ethics as well as the charters of the following committees of our board of directors: Executive; Audit and Corporate Performance; Corporate Governance; Finance; Operations and Nuclear Oversight; Nuclear Project Oversight; and Organization and Compensation. This information is available in print to any shareholder who requests it. Requests should be directed to: Shareholder Relations, Progress Energy, Inc., 410 S. Wilmington Street, Raleigh, NC 27601. Information on our Web site is not incorporated herein and should not be deemed part of this Report.

COMPETITION

RETAIL COMPETITION

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give the Utilities' retail customers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. However, the Utilities compete with suppliers of other forms of energy in connection with their retail customers.

Although there is no pending legislation at this time, if the retail jurisdictions served by the Utilities become subject to deregulation, the recovery of "stranded costs" could become a significant consideration. Stranded costs primarily include the generation assets of utilities whose value in a competitive marketplace would be less than their current book value, as well as above-market purchased power commitments to qualified facilities (QFs). Thus far, all states that have passed restructuring legislation have provided for the opportunity to recover a substantial portion of stranded costs. Assessing the amount of stranded costs for a utility requires various assumptions about future market conditions, including the future price of electricity.

Our largest stranded cost exposure is for PEF's purchased power commitments with QFs, under which PEF has future minimum expected capacity payments through 2025 of $4.5 billion (See Notes 22A and 22B). PEF was obligated to enter into these contracts under provisions of the Public Utilities Regulatory Policies Act of 1978. PEF continues to seek ways to address the impact of escalating payments under these contracts. However, the FPSC allows for full recovery of the retail portion of the cost of power purchased from QFs. PEC does not have significant future minimum expected capacity payments under their purchased power commitments with QFs.

WHOLESALE COMPETITION

The Utilities compete with other utilities and merchant generators for bulk power sales and for sales to municipalities and cooperatives.

Increased competition in the wholesale electric utility industry and the availability of transmission access could affect the Utilities' load forecasts, plans for power supply and wholesale energy sales and related revenues. Wholesale energy sales will be impacted by the extent to which additional generation is available to sell to the wholesale market and the ability of the Utilities to attract new wholesale customers and to retain current wholesale customers who have existing contracts with PEC or PEF.

In June 2009, PEC executed a contract extension with its largest municipal wholesale customer, Public Works Commission of the City of Fayetteville, N.C. The 20-year agreement extends the current contract, representing more than 500 MW of electricity load, through 2032.

Enacted in 2005, the Energy Policy Act of 2005 (EPACT) contains key provisions affecting the electric power industry, including competition among generators of electricity. The FERC has implemented and is considering a number of related regulations to implement EPACT that may impact, among other things, requirements for reliability, QFs, transmission information availability, transmission congestion, security constrained dispatch, energy market transparency, energy market manipulation and behavioral rules. In addition to EPACT, other policies and orders issued by the FERC have supported increased competition within the electric generation industry. EPACT clarified and expanded the FERC's authority to assure that markets operate fairly without imposing new, mandatory intrusion on state authorities.

In February 2007, the FERC issued Order No. 890 adopting a final rule designed to 1) strengthen the pro forma open access transmission tariff (OATT) to ensure that it achieves its original purpose of remedying undue discrimination; 2) provide greater specificity in the pro forma OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect and facilitate the FERC's enforcement; and 3) increase transparency in the rules applicable to planning and use of the transmission system. One of the most significant revisions to the pro forma OATT relates to the development of consistent methodologies for calculating available transfer capability, which determines whether transmission customers can access alternative power supplies. Other significant revisions include: changes to the transmission planning process; reform of energy and generator imbalance penalties; adoption of a “conditional firm” component to long-term point-to-point transmission service and reform of existing requirements for the provision of redispatch service; reform of rollover rights policy; clarification of tariff ambiguities; and increased transparency and customer access to information.

As transmission providers with an OATT on file with the FERC, PEC and PEF are required to comply with the requirements of the rule. A major requirement of the rule was to file a revised pro forma OATT on July 13, 2007. PEC and PEF made the required FERC filing, and both are currently operating under the new tariff. On December 28, 2007, the FERC issued Order No. 890-A granting requests for rehearing and making clarifications to Order No. 890. PEC and PEF made compliance filings on March 17, 2008, in order to meet the requirements of Order 890-A. The FERC approved PEC's and PEF's Order 890-A filings on March 30, 2009.

Effective for PEC on July 1, 2008, and for PEF on January 1, 2008, the Utilities moved from either fixed-revenue requirement or fixed-rate OATT rates to formula-based OATT rates. Under the formula-based rates, the transmission rates are updated each year based on actual costs. The switch to formula-based rates increased PEC’s 2008 revenues by $7 million and increased PEF’s 2008 revenues by $2 million. The rate structure will have a greater impact on PEF in 2011 when all of PEF’s wholesale customers become subject to the new structure. The Utilities filed updated OATT rates in 2009 that increased PEC’s 2009 revenues by $4 million and PEF’s by $2 million.

Certain details related to the rule, such as the precise methodology that will be used to calculate available transfer capability, remain to be determined, and thus it is difficult to make a determination of the overall effect of Order No. 890 on the Utilities’ transmission operations or wholesale marketing function. However, on a preliminary basis, the rule is not anticipated to have a significant impact on the Utilities’ financial results. Nonetheless, the final rule is anticipated to include a wide range of provisions addressing transmission services, and as the new tariff is implemented there is likely to be a significant impact on the Utilities’ transmission operations, planning and wholesale marketing functions.

PEC and PEF are subject to regulation by the FERC with respect to transmission service, including generator interconnection service for facilities making sales for resale and wholesale sales of electric energy. On December 7, 2007, PEC and other major transmission-owning utilities in the Southeast submitted a proposal to FERC for a new regional grid planning process designed to meet FERC directives under Order No. 890 applicable to planning and use of the transmission system. FERC has approved both PEC's and PEF’s regional grid planning processes subject to modification. PEF and PEC filed compliance filings with FERC on October 7, 2008, and December 17, 2008, respectively. PEC received approval from the FERC in January 2010, and PEF is still awaiting FERC approval.

The FERC requires that entities desiring to make wholesale sales of electricity at market-based rates document that they do not possess market power. Market power is exercised when an entity profitably drives up prices through its control of a single activity, such as electricity generation, where it controls a significant share of the total capacity available to the market. The FERC has established screening measures for such determinations. Given the difficulty PEC believed it would experience in passing one of the screens, PEC revised its market-based rate tariffs in 2005 to restrict PEC to sales outside of its control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC’s control area. Accordingly, PEC and PEF make wholesale sales of electricity at cost-based rates in areas inside of PEC’s control area and peninsular Florida and at market-based rates in areas outside of PEC’s control area and peninsular Florida. We do not anticipate that the operations of the Utilities will be materially impacted by this market-based rates decision.

REGIONAL TRANSMISSION ORGANIZATIONS

The FERC’s Order 2000 established national standards for regional transmission organizations (RTOs) and advocated the view that regulated, unbundled transmission would facilitate competition in both wholesale and retail electricity markets. The Utilities previously participated in RTO efforts, but are not currently active in these efforts due to the FERC’s termination of both the GridSouth Transco, LLC (GridSouth) and the GridFlorida RTO proceedings. GridSouth was terminated by the GridSouth participants due to not reaching a consensus on creating a southeastern RTO. GridFlorida was terminated by the FPSC and the FERC due to the conclusion that it was not beneficial to jurisdictional customers. PEC's recorded investment in GridSouth totaled $15 million at December 31, 2009. Excluding the immaterial South Carolina retail portion, the GridSouth costs will be fully amortized and recovered by 2012. PEF fully recovered its development costs in GridFlorida from retail ratepayers through base rates.

FRANCHISE MATTERS

PEC has nonexclusive franchises with varying expiration dates in most of the municipalities in North Carolina and South Carolina in which it distributes electricity. In North Carolina, franchises generally continue for 60 years. In South Carolina, franchises continue in perpetuity unless terminated according to certain statutory methods. The general effect of these franchises is to provide for the manner in which PEC occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. Of these 240 franchises, the majority covers 60-year periods from the date enacted, and 45 have no specific expiration dates. Of the franchise agreements with expiration dates, 15 expire during the period 2010 through 2014, and the remaining agreements expire between 2015 and 2069. PEC also provides service within a number of municipalities and in all of the unincorporated areas within its service area without franchise agreements.

PEF has nonexclusive franchises with varying expiration dates in 110 of the Florida municipalities in which it distributes electricity. PEF also provides service to 11 other municipalities and in all of the unincorporated areas within its service area without franchise agreements. The general effect of these franchises is to provide for the manner in which PEF occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. The franchise agreements cover periods ranging from 10 to 30 years with the majority covering 30-year periods from the date enacted. Of the 110 franchise agreements, 40 expire between 2010 and 2014, and the remaining agreements expire between 2015 and 2037.

REGULATORY MATTERS

HOLDING COMPANY REGULATION

The Parent is a registered public utility holding company subject to regulation by the FERC under PUHCA 2005, including provisions relating to the establishment of intercompany extensions of credit, sales, acquisitions of securities and utility assets, and services performed by PESC. Under PUHCA 2005, the FERC also has authority over accounting and record retention and cost allocation jurisdiction at the election of the holding company system or the state utility commissions with jurisdiction over its utility subsidiaries.

UTILITY REGULATION

FEDERAL REGULATION

The Utilities are subject to regulation by a number of federal regulatory agencies, including the Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), the NRC and the United States Environmental Protection Agency (EPA).

Reliability Standards

The FERC has certified the NERC as the electric reliability organization that will propose and enforce mandatory reliability standards for the bulk power electric system. Included in this certification was a provision for the delegation of authority to audit, investigate and enforce reliability standards in particular regions of the country by entering into delegation agreements with regional entities. In addition, the regional entities have the ability to formulate additional reliability standards in their respective regions, which are required to supplement and be more stringent than the NERC reliability standards. The SERC Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) are the regional entities for PEC and PEF, respectively.

PEC and PEF are currently subject to certain reliability standards as registered users, owners and operators of the bulk power system. We expect existing reliability standards to migrate to more definitive and enforceable requirements over time and additional NERC and regional reliability standards to be approved by the FERC in coming years requiring us to take additional steps to remain compliant. The financial impact of mandatory compliance cannot currently be determined. Failure to comply with the reliability standards could result in the imposition of fines and civil penalties. If we are unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on our financial condition, results of operations and liquidity.

During 2008, PEC self-reported to the SERC three noncompliances with voluntary standards. PEC submitted and completed mitigation plans for these noncompliances with voluntary standards. PEC does not expect enforcement actions on noncompliances to voluntary standards. During 2008, PEC also self-reported to the SERC a violation of a mandatory standard and filed and completed a mitigation plan. PEC and the SERC have reached a settlement agreement on this violation and expect the settlement agreement to be submitted to the FERC for approval during 2010.

During 2009, PEC self-reported to the SERC three violations of mandatory standards. PEC has submitted mitigation plans to the SERC and is currently implementing these mitigation plans. PEC expects to enter into settlement discussions with the SERC for 2009 violations during the first quarter of 2010.

In 2010, PEC self-reported to the SERC four violations of mandatory standards. PEC is developing mitigation plans for submittal to the SERC during the first quarter of 2010.

None of the noncompliances or violations noted above nor the costs of executing the mitigation plans are expected to have a significant impact on our overall compliance efforts, results of operations or liquidity.

During 2008, PEF self-reported to the FRCC four violations of mandatory standards. PEF has filed mitigation plans for the four mandatory violations and completed three of the mitigation plans. The fourth mitigation plan is on schedule and is expected to be completed during 2010. PEF and the FRCC have entered into settlement discussions related to these four violations and expect a settlement to be filed with the FERC during 2010.

During 2009, PEF self-reported to the FRCC eight violations of mandatory standards. PEF has submitted mitigation plans to the FRCC and is currently implementing these mitigation plans. PEF expects to enter into settlement discussions with the FRCC for 2009 violations during the first quarter of 2010.

In 2010, PEF self-reported to the FRCC eight violations of mandatory standards. PEF is developing mitigation plans for submittal to the FRCC during the first quarter of 2010.

None of the violations noted above nor the costs of executing the mitigation plans are expected to have a significant impact on our overall compliance efforts, results of operations or liquidity.

Nuclear

The Utilities' nuclear generating units are regulated by the NRC under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974. The NRC is responsible for granting licenses for the construction, operation and retirement of nuclear power plants and subjects these plants to continuing review and regulation. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. See "Nuclear Matters."

Environmental

The Utilities are also subject to regulation by the EPA. See "Environmental."

STATE REGULATION

PEC is subject to regulation in North Carolina by the North Carolina Utilities Commission (NCUC), and in South Carolina by the Public Service Commission of South Carolina (SCPSC). PEF is subject to regulation in Florida by the FPSC. The Utilities are regulated by their respective regulatory bodies with respect to, among other things, rates and service for electricity sold at retail; retail cost recovery of unusual or unexpected expenses, such as severe storm costs; and issuances of securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus earn a reasonable rate of return on its invested capital, including equity.

Retail Rate Matters

Each of the Utilities' state utility commissions authorize retail "base rates" that are designed to provide the respective utility with the opportunity to earn a reasonable rate of return on its "rate base," or net investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of constructing, operating and maintaining the utility system, except those covered by specific cost-recovery clauses.

In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity of 12.75 percent. The Clean Smokestacks Act enacted in North Carolina in 2002 (Clean Smokestacks Act) froze PEC's retail base rates in North Carolina through December 31, 2007, with provisions that if PEC had experienced extraordinary events beyond its control, PEC could have petitioned for a rate increase. Since 2007, PEC's current North Carolina base rates have continued subject to traditional cost-based rate regulation.

During 2005, the FPSC approved a four-year base rate agreement with PEF. The new base rates took effect the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009, with PEF having the sole option to extend the agreement through the last billing cycle of June 2010, which PEF declined to extend. PEF's base rate agreement also provided for revenue sharing between PEF and its ratepayers with annual adjustment of the threshold and cap amounts. However, PEF's retail base revenues did not exceed the threshold in 2009 and thus no revenues were subject to the revenue-sharing provisions. The threshold and cap were $1.688 billion and $1.742 billion, respectively, for 2009.

In anticipation of the expiration of its current base rate settlement agreement, PEF filed a proposal with the FPSC in 2009 for an increase in base rates effective with the first billing cycle of January 2010. The $499 million request for increased base rates was based, in part, on PEF's investments in its generating fleet and its transmission and distribution systems (See Note 7C). In January 2010, the FPSC voted to grant PEF no increase in base rates above the approximately $132 million annual revenue requirements that had been previously awarded in 2009 as limited rate relief for the repowered Bartow Plant. See Note 7C for details regarding the difference between the $499 million increase in base rates requested and the $132 million increase granted. Among other items, the FPSC authorized a return on equity of 10.5 percent. However, we believe the PEF revenue level approved in January 2010 is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF's right by law to a reasonable opportunity to recover its operating costs and return on invested capital. Consequently, we are currently reviewing our regulatory options in Florida.

Retail Cost-Recovery Clauses

Each of the Utilities' state utility commissions allows recovery of certain costs through various cost-recovery clauses, to the extent the respective commission determines in an annual hearing that such costs, including any past over- or under-recovered costs, are prudent. The clauses are in addition to the Utilities' approved base rates. The Utilities generally do not earn a return on the recovery of eligible operating expenses under such clauses; however, in certain jurisdictions, the Utilities may earn interest on under-recovered costs. Additionally, the commissions may authorize a return for specified investments for energy efficiency and conservation, capacity costs, environmental compliance and utility plant. See MD&A – "Regulatory Matters and Recovery of Costs" for additional discussion regarding cost-recovery clauses.

Costs recovered by the Utilities through cost-recovery clauses, by retail jurisdiction, were as follows:

- *North Carolina Retail* – fuel costs, the fuel and other portions of purchased power (capacity costs for purchases from dispatchable QFs are also recoverable), costs of new DSM and energy-efficiency programs, costs of commodities such as ammonia and limestone used in emissions control technologies (reagents) and eligible renewable energy costs;

- *South Carolina Retail* – fuel costs, certain purchased power costs, costs of reagents, sulfur dioxide (SO_2) and nitrogen oxides (NOx) emission allowance expenses, costs of new DSM and energy-efficiency programs; and

- *Florida Retail* – fuel costs, purchased power costs, capacity costs, qualified nuclear costs, energy conservation expense and specified environmental costs, including Clean Air Interstate Rule (CAIR), SO_2 and NOx emission allowance expenses.

Fuel, fuel-related costs and certain purchased power costs are eligible for recovery by the Utilities. The Utilities use coal, oil, hydroelectric (PEC only), natural gas and nuclear power to generate electricity, thereby maintaining a diverse fuel mix that helps mitigate the impact of cost increases in any one fuel. Due to the associated regulatory treatment and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of the Utilities, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for fuel costs and recovery from ratepayers can adversely impact the timing of cash flow of the Utilities.

As discussed more fully in MD&A – "Other Matters – Regulatory Environment," eligible nuclear costs not previously recoverable through cost-recovery clauses became recoverable in the Florida retail jurisdiction beginning in 2009.

Renewable Energy and Energy-Efficiency Standards

PEC is subject to renewable energy standards at the state level in North Carolina. North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) establishes minimum standards for the use of energy from specified renewable energy resources or implementation of energy-efficiency measures by the state's electric utilities beginning with a 3 percent requirement in 2012 and increasing to 12.5 percent in 2021 for regulated public utilities, including PEC. The premium to be paid by electric utilities to comply with the requirements above the cost they would have otherwise incurred to meet consumer demand is to be recovered through an annual clause. The annual amount that can be recovered through the NC REPS clause is capped and once a utility has expended monies equal to the cap, the utility is deemed to have met its obligations under the NC REPS law, regardless of the actual renewables generated or purchased. The law grants the NCUC authority to modify or alter the NC REPS requirements if the NCUC determines it is in the public interest to do so.

Florida energy law enacted in 2008 includes provisions for development of a renewable portfolio standard for Florida utilities. On January 12, 2009, the FPSC approved a draft Florida renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida renewable portfolio standard rule to the Florida legislature in February 2009, but the legislature did not take action in the 2009 session. We cannot predict the outcome of this matter. Until the rulemaking processes are completed, we cannot predict the costs of complying with the law but PEF would be able to recover its reasonable prudent compliance costs.

On December 30, 2009, the FPSC ordered PEF to adopt DSM goals based on enhanced measures, which will result in significantly higher conservation goals. Under the order, PEF's aggregate conservation goals over the next ten years are: 1,183 Summer MW, 1,072 Winter MW, and 3,488 gigawatt-hours (GWh). PEF has filed a motion for reconsideration with the FPSC to correct what we believe are oversights or errors. If accepted by the FPSC, PEF's motion would adjust conservation goals over the next ten years to: 808 Summer MW, 933 Winter MW, and 1,792 GWh. The FPSC is expected to make a decision in March 2010. We cannot predict the outcome of this matter.

Storm Recovery

As a result of the FPSC's January 11, 2010 base rate approval, PEF may not collect in base rates additional funds for its storm damage reserve. In the event future storms cause the reserve to be depleted, PEF can petition the FPSC for implementation of an interim surcharge to cover any deficiency of its storm reserve. Under Florida law, PEF also may securitize storm costs upon approval by the FPSC. At December 31, 2009, PEF's storm reserve totaled $136 million.

PEC does not maintain a storm damage reserve account and does not have an ongoing regulatory mechanism, such as a surcharge, to recover storm costs. In the past, PEC has sought and received permission from the SCPSC and NCUC to defer and amortize certain storm recovery costs.

See Note 7 for further discussion of regulatory matters.

NUCLEAR MATTERS

GENERAL

The nuclear power industry faces uncertainties with respect to the cost and long-term availability of disposal sites for spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, capital outlays for modifications and new plant construction, the technological and financial aspects of decommissioning plants at the end of their licensed lives and requirements relating to nuclear insurance. Nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

PEC owns and operates four nuclear generating units: Brunswick Nuclear Plant (Brunswick) Unit No. 1 and Unit No. 2, Harris, and Robinson Nuclear Plant (Robinson). The NRC has renewed the operating licenses for all of PEC's nuclear plants. The renewed operating licenses for Brunswick No. 1 and No. 2, Harris and Robinson expire in September 2036, December 2034, October 2046 and July 2030, respectively.

PEF owns and operates one nuclear generating unit, Crystal River Unit No. 3 (CR3). The NRC operating license for CR3 currently expires in December 2016. On December 18, 2008, PEF submitted an application to the NRC requesting a 20-year renewal of the CR3 operating license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

Over time, PEC and PEF have made various modifications of their nuclear facilities to increase the energy output. During CR3's fueling and maintenance outage that began in September 2009, PEF commenced a project to replace CR3's steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure. PEF is finalizing the root cause determination of the delamination event and the necessary repair plans. At present, PEF does not have a firm return to service date for CR3, the finalized repair estimates and replacement power costs, nor the impact of insurance recovery. However, the costs to repair the delamination and associated costs of an outage extension, such as fuel, purchased power and maintenance, could be material. Based on the current understanding of the cause of the delamination event and the conceptual repair strategy, PEF expects that CR3 will return to service in mid-2010.

The NRC periodically issues bulletins and orders addressing industry issues of interest or concern that necessitate a response from the industry. It is our intent to comply with and to complete required responses in a timely and accurate manner. Any potential impact to company operations will vary and will be dependent upon the nature of the requirement(s).

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on nuclear construction, we continue to take steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida (See Item 1A, "Risk Factors"). The NRC estimates that it will take approximately three to four years to review and process the COL applications. We have focused on the potential nuclear plant construction in Florida given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions as well as existing state legislative policy that is supportive of nuclear projects.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. On April 17, 2008, the NRC docketed, or accepted for review, the Harris application. Docketing the application does not preclude additional requests for information as the review proceeds; nor does it indicate whether the NRC will issue the license. No petitions to intervene have been admitted in the Harris COL application. We cannot predict the outcome of this matter. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until at least 2019.

On December 12, 2006, we announced that PEF selected Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. On July 30, 2008, PEF filed its COL application with the NRC for two reactors. The FPSC issued the final order granting PEF's petition for the Determination of Need for Levy on August 12, 2008. On October 6, 2008, the NRC docketed, or accepted for review, the Levy nuclear project application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. One joint petition to intervene in the licensing proceeding was filed with the NRC within the required 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. On July 8, 2009, the Atomic Safety and Licensing Board (ASLB) issued a decision accepting three of the 12 contentions submitted. The admitted contentions involved questions about the storage of low-level radioactive waste, the potential impacts of plant construction and operation on the aquifer and surrounding waters and the potential impact of salt water drift from cooling tower operation. PEF's appeal of the ASLB's decision was denied and it is expected at this time that a hearing on the contentions will be conducted in 2011. Other COL applicants have received similar petitions raising similar potential contentions. On December 31, 2008, PEF signed an agreement with Westinghouse Electric Company LLC and Stone & Webster, Inc. for the engineering, procurement and construction of two nuclear units at Levy. The contract price for the two Levy units combined is approximately $7.650 billion, part of which is subject to agreed upon escalation factors. The total escalated cost for the two generating units was estimated to be approximately $14 billion in PEF's petition for the Determination of Need for Levy, including land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. The necessary transmission equipment and approximately 200 miles of transmission lines associated with the project was estimated to cost an additional $3 billion.

In 2009, the NRC indicated it would not process PEF's limited work authorization request until after COL issuance. This factor alone resulted in a minimum 20-month in-service schedule shift for the Levy units. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions, and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule.

SECURITY

The NRC has issued various orders since September 2001 with regard to security at nuclear plants. These orders include additional restrictions on nuclear plant access, increased security measures at nuclear facilities and closer coordination with our partners in intelligence, military, law enforcement and emergency response at the federal, state and local levels. We completed the requirements as outlined in the orders by the committed dates. As the NRC, other governmental entities and the industry continue to consider security issues, it is possible that more extensive security plans could be required.

SPENT FUEL AND OTHER HIGH-LEVEL RADIOACTIVE WASTE

The Nuclear Waste Policy Act of 1982 provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The Nuclear Waste Policy Act of 1982 promotes increased usage of interim storage of spent nuclear fuel at existing nuclear plants. We will continue to maximize the use of spent fuel storage capability within our own facilities for as long as feasible.

With certain modifications and additional approvals by the NRC, including the installation and/or expansion of on-site dry cask storage facilities at Robinson, Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on their respective systems through the expiration of the operating licenses, including any license renewals, for their nuclear generating units. Harris has sufficient storage capacity through the expiration of its renewed operating licenses.

See MD&A – "Other Matters – Nuclear – Spent Nuclear Fuel Matters" and Note 22D, respectively, for discussion of the status of permanent disposal facilities and the Utilities' contracts with the DOE for spent nuclear fuel storage.

DECOMMISSIONING

In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the respective state utility commissions and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdiction, the provisions for nuclear decommissioning costs are approved by the FERC. A condition of the operating license for each unit requires an approved plan for decontamination and decommissioning. See Note 4D for a discussion of the Utilities' nuclear decommissioning costs.

ENVIRONMENTAL

GENERAL

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be precisely estimated. The current estimated capital costs associated with compliance with pollution control laws and regulations that we expect to incur are included within MD&A – "Liquidity and Capital Resources – Capital Expenditures" and within MD&A – "Other Matters – Environmental Matters."

We have a formal environmental management system to manage the environmental aspects and impacts to our businesses, which generally follows the international ISO 14001 standard. We have established a process to identify environmental risks, take prompt action to address these issues and ensure appropriate senior management oversight on a routine basis. Our business units assume daily responsibility for ensuring environmental compliance and are supported by several corporate organizations, including technical environmental professionals, governance and risk management staff and an energy policy and strategy group. The actions of these organizations are guided by our Environmental, Health and Safety Performance Council, which is composed of senior executives. The Environmental, Health and Safety Performance Council provides overall strategic direction, guides corporate environmental policy, monitors environmental regulatory compliance and approves targets that measure, track and drive performance. Our environmental activities are reported to our board of directors' Operations and Nuclear Oversight Committee. The committee is responsible for climate change oversight and strategy and therefore assesses our plans and activities and makes recommendations to the full board regarding these matters.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liability. Some states, including North Carolina, South Carolina and Florida, have similar types of legislation. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation.

There are presently hazardous waste sites, including the Ward Transformer site (Ward) and several manufactured gas plant (MGP) sites, with respect to which we have been notified by the EPA, the State of North Carolina or the State of Florida of our potential liability, as a potentially responsible party (PRP). We have accrued costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. While we accrue for probable costs that can be reasonably estimated, based upon the current status of some sites, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition and results of operations.

GLOBAL CLIMATE CHANGE

Global climate change is one of the primary corporate environmental risks identified by our environmental management system. Our risks associated with climate change are discussed under Item 1A, "Risk Factors."

Growing state, federal and international attention to global climate change may result in the regulation of carbon dioxide (CO_2) and other GHGs. The full impact of final legislation, if enacted and additional regulation resulting from other GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant rate increases over time to recover the costs of compliance.

As previously discussed under "Recent Developments," we are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. We are taking steps to address global climate change by changing the way we make electricity through our balanced solution strategy of energy efficiency, alternative energy and state-of-the-art power generation as discussed in MD&A – "Other Matters – Energy Demand." We continuously evaluate new generation options to determine if they are realistic for the Southeastern United States where our operations are located.

See Note 21 and MD&A – "Other Matters – Environmental Matters" for additional discussion of our environmental matters, including specific environmental issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

EMPLOYEES

At February 19, 2010, we employed approximately 11,000 full-time employees. Of this total, approximately 2,000 employees at PEF are represented by the International Brotherhood of Electrical Workers. Progress Energy and the International Brotherhood of Electrical Workers entered into a new three-year labor contract that began December 2008. We consider our relationship with employees, including those covered by collective bargaining agreements, to be good.

We have a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees and an employee stock ownership plan among other employee benefits. We also provide contributory postretirement benefits, including certain health care and life insurance benefits, for substantially all retired employees.

At February 19, 2010, PEC and PEF employed approximately 5,500 and 4,000 full-time employees, respectively.

PEC

GENERAL

PEC is a regulated public utility founded in North Carolina in 1908 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. At December 31, 2009, PEC had a total summer generating capacity (including jointly owned capacity) of 12,585 MW. For additional information about PEC's generating plants, see "Electric – PEC" in Item 2, "Properties." PEC's system normally experiences its highest peak demands during the summer, and the all-time system peak of 12,656 megawatt-hours (MWh) was set on August 9, 2007.

PEC's service territory covers approximately 34,000 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. At December 31, 2009, PEC was providing electric services, retail and wholesale, to approximately 1.5 million customers. Major wholesale power sales customers include North Carolina Eastern Municipal Power Agency (Power Agency), North Carolina Electric Membership Corporation and Public Works Commission of the City of Fayetteville, North Carolina. PEC is subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the NRC. No single customer accounts for more than 10 percent of PEC's revenues.

PEC's net income available to parent was $513 million, $531 million and $498 million for the years ended December 31, 2009, 2008 and 2007, respectively. PEC's total assets were $13.502 billion and $13.165 billion at December 31, 2009 and 2008, respectively.

BILLED ELECTRIC REVENUES

PEC's electric revenues billed by customer class, for the last three years, are shown as a percentage of total PEC electric revenues in the table below:

	2009	2008	2007
Residential	**39%**	38%	37%
Commercial	**27%**	26%	26%
Wholesale	**16%**	17%	18%
Industrial	**16%**	17%	17%
Other retail	**2%**	2%	2%

Major industries in PEC's service area include chemicals, textiles, paper, food, metals, rubber and plastics, wood products and stone products.

FUEL AND PURCHASED POWER

SOURCES OF GENERATION

PEC's consumption of various types of fuel depends on several factors, the most important of which are the demand for electricity by PEC's customers, the availability of various generating units, the availability and cost of fuel and the requirements of federal and state regulatory agencies.

PEC's total system generation (including jointly owned capacity) by primary energy source, along with purchased power for the last three years is presented in the following table:

	2009	2008	2007
Coal	**44%**	45%	48%
Nuclear	**44%**	43%	42%
Oil/Gas	**6%**	4%	4%
Purchased power	**5%**	7%	5%
Hydro	**1%**	1%	1%

PEC is generally permitted to pass the cost of fuel and certain purchased power costs to its customers through fuel cost-recovery clauses. The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. See "Commodity Price Risk" under Item 7A, "Quantitative And Qualitative Disclosures About Market Risk" and Item 1A, "Risk Factors." However, PEC believes that its fuel supply contracts, as described below and in Note 22A, will be adequate to meet its fuel supply needs.

PEC's average fuel costs per million British thermal units (Btu) for the last three years were as follows:

(per million Btu)	**2009**	2008	2007
Coal	**$3.82**	$3.39	$2.96
Nuclear	**0.53**	0.46	0.44
Oil	**14.84**	16.05	12.28
Gas	**8.16**	10.66	9.19
Weighted-average	**2.60**	2.44	2.21

Changes in the unit price for coal, oil and gas are due to market conditions. Because these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income.

Coal

PEC anticipates a burn requirement of approximately 13.5 million tons of coal in 2010. Almost all of the coal will be supplied from Appalachian coal sources and will be primarily delivered by rail.

For 2010, PEC has short-term, intermediate and long-term agreements from various sources for approximately 100 percent of its estimated burn requirements of its coal units. The contracts have expiration dates ranging from one to ten years. PEC will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements.

As discussed within MD&A – "Results of Operation – Progress Energy Carolina – Operation and Maintenance," PEC has announced that it intends to permanently shut-down certain coal-fired units representing approximately 30 percent of its coal-fired power generation fleet between 2013 and the end of 2017 as part of a major coal-to-gas modernization strategy. See "Oil and Gas" for planned gas facilities.

Nuclear

Nuclear fuel is processed through four distinct stages. Stages I and II involve the mining and milling of the natural uranium ore to produce a uranium oxide concentrate and the conversion of this concentrate into uranium hexafluoride. Stages III and IV entail the enrichment of the uranium hexafluoride and the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

PEC has sufficient uranium, conversion, enrichment and fabrication contracts to meet its nuclear fuel requirement needs for the foreseeable future. PEC's nuclear fuel contracts typically have terms ranging from three to fifteen years. For a discussion of PEC's plans with respect to spent fuel storage, see "Nuclear Matters."

Oil and Gas

Oil and natural gas supply for PEC's generation fleet is purchased under term and spot contracts from various suppliers and PEC has derivative instruments limit its exposure to price fluctuations. PEC has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEC's oil and gas is either at a fixed price or determined by market prices as reported in certain industry publications. PEC believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEC's natural gas transportation for its gas generation is purchased under term firm transportation contracts with interstate pipelines. PEC also purchases capacity under other contracts and utilizes transportation for its peaking load requirements.

The NCUC has granted PEC permission to construct two new generating facilities: a 600-MW combined cycle dual-fuel facility at its Richmond County, N.C. generating facility and a 950-MW combined cycle natural gas-fueled facility at a site in Wayne County, N.C. The facilities are expected to be placed in service in 2011 and 2013, respectively. PEC has also filed for approval to construct a 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C., projected to be placed in service by late 2013 or early 2014.

Purchased Power

PEC purchased approximately 3.3 million MWh, 4.8 million MWh and 3.9 million MWh of its system energy requirements during 2009, 2008 and 2007, respectively, under purchase obligations and operating leases and had 1,309 MW of firm purchased capacity under contract during 2009. PEC may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEC believes that it can obtain adequate purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

Hydroelectric

PEC has three hydroelectric generating plants licensed by the FERC: Walters, Tillery and Blewett. PEC also owns the Marshall Plant, which has a license exemption. The total summer generating capacity for all four units is 225 MW. PEC submitted an application to relicense for 50 years its Tillery and Blewett Plants and anticipates a decision by the FERC in 2010. The Walters Plant license will expire in 2034.

PEF

GENERAL

PEF is a regulated public utility founded in Florida in 1899 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. At December 31, 2009, PEF had a total summer generating capacity (including jointly owned capacity) of 10,013 MW. For additional information about PEF's generating plants, see "Electric – PEF" in Item 2, "Properties." PEF's system normally experiences its highest peak demands during the winter, and the all-time system peak of 10,822 MWh was set on January 11, 2010.

PEF's service territory covers approximately 20,000 square miles in west central Florida, and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 22 municipal and 9 rural electric cooperative systems. At December 31, 2009, PEF was providing electric services, retail and wholesale, to approximately 1.6 million customers. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Florida Municipal Power Agency, the city of Gainesville, Tampa Electric Company, and Reedy Creek Improvement District. PEF is subject to the rules and regulations of the FERC, the FPSC and the NRC. No single customer accounts for more than 10 percent of PEF's revenues.

PEF's net income available to parent was $460 million, $383 million and $315 million for the years ended December 31, 2009, 2008 and 2007, respectively. PEF's total assets were $13.100 billion and $12.471 billion at December 31, 2009 and 2008, respectively.

BILLED ELECTRIC REVENUES

PEF's electric revenues billed by customer class, for the last three years, are shown as a percentage of total PEF electric revenues in the table below:

	2009	2008	2007
Residential	**53%**	50%	52%
Commercial	**26%**	25%	25%
Wholesale	**8%**	12%	9%
Industrial	**6%**	7%	7%
Other retail	**7%**	6%	7%

Major industries in PEF's territory include phosphate rock mining and processing, electronics design and manufacturing, and citrus and other food processing. Other major commercial activities are tourism, health care, construction and agriculture.

FUEL AND PURCHASED POWER

SOURCES OF GENERATION

PEF's consumption of various types of fuel depends on several factors, the most important of which are the demand for electricity by PEF's customers, the availability of various generating units, the availability and cost of fuel and the requirements of federal and state regulatory agencies.

PEF's total system generation (including jointly owned capacity) by primary energy source, along with purchased power for the last three years is presented in the following table:

	2009	2008	2007
Oil/Gas	**44%**	34%	32%
Coal	**25%**	30%	31%
Purchased Power	**20%**	21%	23%
Nuclear	**11%**	15%	14%

PEF is generally permitted to pass the cost of fuel and certain purchased power to its customers through fuel cost-recovery clauses. The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. See "Commodity Price Risk" under Item 7A, "Quantitative And Qualitative Disclosures About Market Risk" and Item 1A, "Risk Factors." However, PEF believes that its fuel supply contracts, as described below and in Note 22A, will be adequate to meet its fuel supply needs.

PEF's average fuel costs per million Btu for the last three years were as follows:

(per million Btu)	**2009**	2008	2007
Oil	**$11.43**	$9.24	$8.54
Gas	**8.40**	10.03	8.51
Coal	**4.25**	3.74	3.28
Nuclear	**0.52**	0.49	0.48
Weighted-average	**5.88**	5.67	4.85

Changes in the unit price for coal, oil and gas are due to market conditions. Because these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income.

Oil and Gas

Oil and natural gas supply for PEF's generation fleet is purchased under term and spot contracts from various suppliers and PEF has derivative instruments to limit its exposure to price fluctuations. PEF has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEF's oil and gas is either at a fixed price or determined by market prices as reported in certain industry publications. PEF believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEF's natural gas transportation for its gas generation is purchased under term firm transportation contracts with interstate pipelines. PEF also purchases capacity under other contracts and utilizes transportation for its peaking load requirements.

Coal

PEF anticipates a requirement of approximately 5.5 million tons of coal in 2010. Approximately 60 percent of the coal is expected to be supplied from Appalachian coal sources and 40 percent supplied from coal sources in the Illinois Basin and Colorado. Approximately 30 percent of the coal is expected to be delivered by rail and the remainder by water.

For 2010, PEF has intermediate and long-term contracts from various sources for approximately 100 percent of its estimated burn requirements of its coal units. These contracts have price adjustment provisions and have expiration dates ranging from one to ten years.

Purchased Power

PEF purchased approximately 8.7 million MWh, 10.2 million MWh and 11.1 million MWh of its system energy requirements during 2009, 2008 and 2007, respectively, under purchase obligations, operating leases and capital leases and had 1,847 MW of firm purchased capacity under contract during 2009. These agreements include approximately 682 MW of firm capacity under contract with certain QFs. PEF may need to acquire additional purchased power capacity in the future to accommodate a portion of its system load needs. PEF believes that it can obtain adequate purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

Nuclear

Nuclear fuel is processed through four distinct stages. Stages I and II involve the mining and milling of the natural uranium ore to produce a uranium oxide concentrate and the conversion of this concentrate into uranium hexafluoride. Stages III and IV entail the enrichment of the uranium hexafluoride and the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

PEF has sufficient uranium, conversion, enrichment and fabrication contracts to meet its nuclear fuel requirement needs for the foreseeable future. PEF's nuclear fuel contracts typically have terms ranging from three to fifteen years. For a discussion of PEF's plans with respect to spent fuel storage, see "Nuclear Matters."

CORPORATE AND OTHER

Corporate and Other primarily includes the operations of the Parent and PESC. The Parent's unallocated interest expense is included in Corporate and Other. PESC provides centralized administrative, management and support services to our subsidiaries, which generates essentially all of the segment's revenues. See Note 18 for additional information about PESC services provided and costs allocated to subsidiaries. This segment also includes miscellaneous nonregulated business areas that do not separately meet the quantitative disclosure requirements as a reportable business segment.

The Corporate and Other segment's net loss attributable to controlling interests was $216 million, $84 million and $309 million for the years ended December 31, 2009, 2008 and 2007, respectively. Corporate and Other segment total assets were $20.538 billion and $17.483 billion at December 31, 2009 and 2008, respectively, which were primarily comprised of the Parent's investments in subsidiaries.

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PROGRESS ENERGY

	Years Ended December 31				
	2009	2008	2007	2006	2005
Energy supply (millions of kWh)					
Generated					
Steam	**40,420**	46,771	51,163	48,770	52,306
Nuclear	**29,412**	30,565	30,336	30,602	30,120
Combustion Turbines/Combined Cycle	**21,254**	15,557	13,319	11,857	11,349
Hydro	**651**	429	415	594	749
Purchased	**11,996**	14,956	14,994	14,664	14,566
Total energy supply (Company share)	**103,733**	108,278	110,227	106,487	109,090
Jointly owned share [(a)]	**5,500**	5,780	5,351	5,224	5,388
Total system energy supply	**109,233**	114,058	115,578	111,711	114,478
Average fuel cost (per million Btu)					
Fossil	**$ 5.50**	$ 5.35	$ 4.54	$ 4.17	$ 4.05
Nuclear fuel	**$ 0.53**	$ 0.46	$ 0.45	$ 0.44	$ 0.44
All fuels	**$ 3.79**	$ 3.66	$ 3.17	$ 2.86	$ 2.83
Energy sales (millions of kWh)					
Retail					
Residential	**36,516**	36,328	37,112	36,280	36,558
Commercial	**25,523**	26,080	26,215	25,333	25,258
Industrial	**13,653**	15,174	15,721	16,553	16,856
Other Retail	**4,753**	4,768	4,805	4,695	4,608
Unbilled	**491**	(107)	(61)	(272)	(460)
Wholesale	**17,801**	21,063	21,333	19,018	21,157
Total energy sales	**98,737**	103,306	105,125	101,607	103,977
Company uses and losses	**4,996**	4,972	5,102	4,880	5,113
Total energy requirements	**103,733**	108,278	110,227	106,487	109,090
Operating revenues (in millions)					
Retail					
Billed	**$ 8,449**	$ 7,585	$ 7,672	$ 7,429	$ 6,607
Unbilled	**14**	7	1	(6)	(2)
Wholesale	**1,114**	1,288	1,191	1,039	1,103
Miscellaneous revenue	**301**	280	270	263	238
Total operating revenues of the Utilities	**$ 9,878**	$ 9,160	$ 9,134	$ 8,725	$ 7,946

(a) Amounts represent joint owners' share of the energy supplied from the six generating facilities that are jointly owned.

REGULATED OPERATING STATISTICS – PEC

	Years Ended December 31				
	2009	2008	2007	2006	2005
Energy supply (millions of kWh)					
Generated					
Steam	**27,261**	28,363	30,770	28,985	29,780
Nuclear	**24,467**	24,140	24,212	24,220	24,291
Combustion Turbines/Combined Cycle	**3,634**	2,795	2,960	2,106	2,475
Hydro	**651**	429	415	594	749
Purchased	**3,251**	4,735	3,901	4,229	4,656
Total energy supply (Company share)	**59,264**	60,462	62,258	60,134	61,951
Jointly owned share [(a)]	**5,057**	5,205	4,800	4,649	4,857
Total system energy supply	**64,321**	65,667	67,058	64,783	66,808
Average fuel cost (per million Btu)					
Fossil	**$ 4.30**	$ 4.01	$ 3.50	$ 3.37	$ 3.30
Nuclear fuel	**$ 0.53**	$ 0.46	$ 0.44	$ 0.43	$ 0.42
All fuels	**$ 2.60**	$ 2.44	$ 2.21	$ 2.06	$ 2.03
Energy sales (millions of kWh)					
Retail					
Residential	**17,117**	17,000	17,200	16,259	16,664
Commercial	**13,639**	13,941	14,032	13,358	13,313
Industrial	**10,368**	11,388	11,901	12,393	12,716
Other Retail	**1,497**	1,466	1,438	1,419	1,410
Unbilled	**360**	(8)	(55)	(137)	(235)
Wholesale	**13,966**	14,329	15,309	14,584	15,673
Total energy sales	**56,947**	58,116	59,825	57,876	59,541
Company uses and losses	**2,317**	2,346	2,433	2,258	2,410
Total energy requirements	**59,264**	60,462	62,258	60,134	61,951
Operating revenues (in millions)					
Retail					
Billed	**$ 3,801**	$ 3,582	$ 3,534	$ 3,268	$ 3,133
Unbilled	**5**	8	–	(1)	4
Wholesale	**707**	737	754	720	759
Miscellaneous revenue	**114**	102	97	99	95
Total operating revenues	**$ 4,627**	$ 4,429	$ 4,385	$ 4,086	$ 3,991

[(a)] Amounts represent joint owner's share of the energy supplied from the four generating facilities that are jointly owned.

REGULATED OPERATING STATISTICS – PEF

	Years Ended December 31				
	2009	2008	2007	2006	2005
Energy supply (millions of kWh)					
Generated					
Steam	**13,159**	18,408	20,393	19,785	22,526
Nuclear	**4,945**	6,425	6,124	6,382	5,829
Combustion Turbines/Combined Cycle	**17,620**	12,762	10,359	9,751	8,874
Purchased	**8,745**	10,221	11,093	10,435	9,910
Total energy supply (Company share)	**44,469**	47,816	47,969	46,353	47,139
Jointly owned share [(a)]	**443**	575	551	575	531
Total system energy supply	**44,912**	48,391	48,520	46,928	47,670
Average fuel cost (per million Btu)					
Fossil	**$ 6.88**	$ 6.87	$ 5.80	$ 5.09	$ 4.88
Nuclear fuel	**$ 0.52**	$ 0.49	$ 0.48	$ 0.50	$ 0.51
All fuels	**$ 5.88**	$ 5.67	$ 4.85	$ 4.21	$ 4.15
Energy sales (millions of kWh)					
Retail					
Residential	**19,399**	19,328	19,912	20,021	19,894
Commercial	**11,884**	12,139	12,183	11,975	11,945
Industrial	**3,285**	3,786	3,820	4,160	4,140
Other Retail	**3,256**	3,302	3,367	3,276	3,198
Unbilled	**131**	(99)	(6)	(135)	(225)
Wholesale	**3,835**	6,734	6,024	4,434	5,484
Total energy sales	**41,790**	45,190	45,300	43,731	44,436
Company uses and losses	**2,679**	2,626	2,669	2,622	2,703
Total energy requirements	**44,469**	47,816	47,969	46,353	47,139
Operating revenues (in millions)					
Retail					
Billed	**$ 4,648**	$ 4,003	$ 4,138	$ 4,161	$ 3,474
Unbilled	**9**	(1)	1	(5)	(6)
Wholesale	**407**	551	437	319	344
Miscellaneous revenue	**187**	178	173	164	143
Total operating revenues	**$ 5,251**	$ 4,731	$ 4,749	$ 4,639	$ 3,955

[(a)] Amounts represent joint owners' share of the energy supplied from the two generating facilities that are jointly owned.

ITEM 1A. RISK FACTORS

Investing in the securities of the Progress Registrants involves risks, including the risks described below, that could affect the Progress Registrants and their businesses, as well as the energy industry in general. Most of the business information, as well as the financial and operational data contained in our risk factors is updated periodically in the reports the Progress Registrants file with the SEC. Before purchasing securities of the Progress Registrants, you should carefully consider the following risks and the other information in this combined Annual Report, as well as the documents the Progress Registrants file with the SEC from time to time. Each of the risks described below could result in a decrease in the value of the securities of the Progress Registrants and your investment therein.

Solely with respect to this Item 1A, "Risk Factors," unless the context otherwise requires or the disclosure otherwise indicates, references to "we," "us" or "our" are to each of the individual Progress Registrants, and the matters discussed are generally applicable to each Progress Registrant.

We are subject to fluid and complex government regulations that may have a negative impact on our business, financial condition and results of operations .

We are subject to comprehensive regulation by multiple federal, state and local regulatory agencies, which significantly influences our operating environment and may affect our ability to recover costs from utility customers. We are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of our business, including customer rates, retail service territories, reliability of our transmission system, applicable renewable energy and energy-efficiency standards, environmental compliance, issuances of securities, asset acquisitions and sales, accounting policies and practices, and the operation of generating facilities. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws. Changes in laws and regulations as well as changes in federal administrative policy are ongoing and the ultimate costs of compliance cannot be precisely estimated. Such changes could have an adverse impact on our financial condition and results of operations.

The rates that PEC and PEF may charge retail customers for electric power are subject to the authority of state regulators. Accordingly, our profit margins and ability to earn an adequate return on investment could be adversely affected if we do not control and prudently manage costs to the satisfaction of regulators, or if we do not obtain successful outcomes in our regulatory proceedings. Such regulatory decisions may be impacted by economic and public policy considerations within the respective jurisdictions.

The NCUC, the SCPSC and the FPSC each exercise regulatory authority for review and approval of the retail electric power rates charged within its respective state. The Utilities' state utility commissions approve base rates, which by law must give a utility a reasonable opportunity to recover its operating costs and return on invested capital. They also approve recovery of certain additional costs, known as "pass-through" costs, over and above base rates through cost-recovery clauses, which vary by jurisdiction; examples include fuel costs, certain purchased power costs, qualified nuclear costs and specified environmental costs. The commissions can disagree with our request of appropriate base rates, and can disallow either requested base rates or pass-through recoveries on the grounds that such costs were not reasonable and prudent .

The Utilities expect increased future expenditures in several key areas including, but not limited to, environmental compliance, new and existing generation, transmission and distribution facilities, renewable energy and energy-efficiency standards compliance (as applicable), DSM programs and fuel and other commodities. Such cost increases will be subject to scrutiny from regulators, policymakers and ratepayers. As referenced above, the commissions may disallow any costs that they find unreasonable and imprudent.

Our financial performance depends on the successful operation of electric generating facilities by the Utilities and their ability to deliver electricity to customers.

Operating our electric generating facilities and delivery systems involves many risks, including:

- operator error and breakdown or failure of equipment or processes, including repair and replacement power costs;
- failure of information technology systems and network infrastructure;
- operational limitations imposed by environmental or other regulatory requirements;
- inadequate or unreliable access to transmission and distribution assets;
- labor disputes and inability to recruit and retain skilled technical workers;
- inability to successfully and timely execute repair, maintenance and/or refueling outages;
- interruptions to the supply of fuel and other commodities used in generation;
- failure to comply with FERC-mandated reliability standards for the bulk power electric system;
- inadequate coal combustion product management (disposal or beneficial use) capabilities; and
- catastrophic events such as hurricanes, floods, extreme drought, earthquakes, fires, explosions, terrorist attacks, pandemic health events or other similar occurrences.

Occurrences of these events could adversely affect our financial condition or results of operations.

Meeting the anticipated demand in our service territories and fulfilling our environmental compliance strategies will require, among other things, modernization of coal generation facilities, the construction within the next decade of new generation facilities and the siting and construction of associated transmission facilities. We may not be able to obtain required licenses, permits and rights-of-way; successfully and timely complete construction; or recover the cost of such new generation and transmission facilities through our base rates or other recovery mechanisms, any of which could adversely impact our financial condition, cash flows or results of operations.

Meeting the anticipated demand within the Utilities' service territories and complying with existing and potential environmental laws and regulations will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our energy-efficiency programs; (2) investing in the development of alternative energy resources for the future; and (3) operating state-of-the-art plants that produce energy cleanly and efficiently by modernizing existing plants and pursuing options for building new plants and associated transmission facilities.

The risks of each of the elements of our balanced solution include, but are not limited to, the following:

Energy-Efficiency and New Energy Resources

We are expanding our DSM, energy-efficiency and conservation programs and will continue to pursue additional initiatives as these programs can be effective ways to reduce energy costs, offset the need for new power plants and protect the environment.

We are subject to the risk that our customers may not participate in our conservation programs or that the results from these programs may be less than anticipated. This could impact our compliance with state-mandated energy-efficiency standards as discussed in the risks regarding renewable energy standards. Also, not achieving the energy-efficiency and conservation measurements we assumed in our long-term resource planning could require us to further expand our generation or purchase additional power at prevailing market rates.

We are also subject to the risk that customer participation in these programs or new technologies that impact the quantity and pattern of electricity usage may decrease our electric sales and require us to seek future rate increases to cover our prudently incurred costs.

As discussed further in the risk factor related to renewable energy standards, we are actively engaged in a variety of alternative energy projects. These alternative energy projects may be determined to not be cost-efficient or cost-effective.

Modernization and Construction of Generating Plants

We are currently evaluating our options for new generating plants, including gas and nuclear technologies. In 2009, we announced our intention to retire certain coal-fired units in North Carolina that do not have emission control equipment and to construct new natural gas-fueled units at certain of these facilities. We are also evaluating the possibility of converting certain of these facilities to be fueled by natural gas or biomass. At this time, no definitive decision has been made regarding the construction of nuclear plants.

Decisions to build new power plants and successful completion of such construction projects are based on many factors including:

- projected system load growth;
- performance of existing generation fleet;
- availability of competitively priced alternative energy sources;
- projections of fuel prices, availability and security;
- the regulatory environment, including the ability to recover costs and earn an appropriate return on investment;
- operational performance of new technologies;
- the time required to permit and construct;
- environmental impact;
- both public and policymaker support, including support for siting of power plant and associated transmission;
- siting and construction of transmission facilities;
- cost and availability of construction equipment, materials and skilled labor;
- nuclear decommissioning costs, insurance, and costs of security;
- ability to obtain financing on favorable terms; and
- availability of adequate water supply.

There is no assurance that we will be able to successfully and timely construct new generation facilities or to expand or modernize existing facilities within our projected budgets or that those expenditures will be recoverable through our base rates or other recovery mechanisms. As with any major construction undertaking, completion could be delayed or prevented, or cost overruns could be incurred, as a result of numerous factors, including shortages of material and labor, labor disputes, weather interferences, difficulties in obtaining necessary licenses or permits or complying with license or permit conditions, and unforeseen engineering, environmental or geological problems. These construction projects are long-term and may involve facility designs that have not been previously constructed or that have not been finalized when that project is commenced. Consequently, the projects potentially could be subject to significant cost increases for labor, materials, scope changes and changes in design. Unsuccessful construction, expansion or modernization efforts could be subject to additional costs and/or the write-off of our investment in the project or improvement.

The construction of new power plants and associated expansion of our transmission system will require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support the construction. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital. For certain new baseload generation facilities, we may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks, but we cannot be certain we will be able to successfully negotiate any such arrangement. Furthermore, joint ventures or joint ownership arrangements also present risks and uncertainties, including those associated with sharing control over the construction and operation of a facility and reliance on the other party's financial or operational strength.

Our assumptions regarding future growth and resulting power demand in our service territories may not be realized. Like other parts of the United States, our service territories and business have been negatively impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. We may increase our baseload capacity based on anticipated growth levels and have excess capacity if those levels are not realized. The resulting excess capacity may exceed the reserve margins established by the NCUC, SCPSC and FPSC to meet our obligation to serve retail customers and, as a result, may not be recoverable.

Nuclear

In addition to the risks discussed above, the successful construction of a new nuclear power plant requires the satisfaction of a number of conditions. The conditions include, but are not limited to, the continued operation of the industry's existing nuclear fleet in a safe, reliable and cost-effective manner, an efficient and successful licensing process and a viable program for managing spent nuclear fuel. We cannot provide certainty that these conditions will exist. While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. We will continue to evaluate the ongoing viability of our nuclear construction projects based on certain criteria, including obtaining the COL, public, regulatory and political support; adequate financial cost-recovery mechanisms; and availability and terms of capital financing. Adverse changes in these criteria could result in project cost increases or project termination.

PEF has entered into an EPC agreement for Levy. More than half of the contract price is fixed or firm with agreed upon escalation factors. Generally, the EPC contractor will not be obligated to pay liquidated damages for events or circumstances that adversely affect its ability to fulfill its obligations to the extent that the events or circumstances are beyond its reasonable control and are not caused by its or its subcontractors' negligence or lack of due diligence and could not have been avoided by the use of its reasonable efforts. For termination without cause, the EPC agreement contains exit provisions with termination fees and costs, which may be significant, that vary based on the termination circumstance. Under the EPC agreement, we are responsible for a number of matters in connection with the construction, completion and start-up of Levy, including obtaining the COL; performance, oversight and review of certain surveillance and testing functions; and acceptance of turnover of systems from the EPC contractor. Because of anticipated schedule shifts, we are negotiating an amendment to the EPC agreement. If Levy is deferred or cancelled, PEF may incur additional contract suspension, termination and exit costs that would increase its unrecovered investment. The magnatitude of these contract suspension, termination and/or exit costs cannot be determined at this time.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant constructed by us would qualify for these incentives.

In addition, other COL applicants would be pursuing regulatory approval, permitting and construction at roughly the same time as we would. Consequently, there may be shortages of qualified individuals to design, construct and operate these proposed new nuclear facilities.

Gas

In addition to the risks discussed above, the successful construction of a gas-fired plant requires access to an adequate supply of natural gas. The gas pipeline infrastructure in eastern and western North Carolina is limited. Existing pipelines will have to be extended to the new plant locations prior to commencement of operations, which introduces the risks associated with a critical construction project not under our direct control. Power plants fueled by fossil fuels such as natural gas and fuel oil emit GHG, which may be subject to future regulation.

Coal

In addition to the risks discussed above, the successful modernization of a coal-fired power plant requires the satisfaction of a number of conditions, including, but not limited to, consideration of emissions that impact air and water quality and management of coal combustion products such as slag, bottom ash and fly ash.

We are subject to renewable energy standards that may have a negative impact on our business, financial condition and results of operations .

We are subject to state renewable energy standards in North Carolina. North Carolina's standards include use of energy from specified renewable energy resources or implementation of energy-efficiency measures totaling 12.5 percent by 2021. Florida energy law enacted in 2008 includes provisions for development of a renewable portfolio standard but the rulemaking process is not complete. We may be subject to additional state or federal level standards in the future that could require the Utilities to produce or buy a higher portion of their energy from renewable energy sources. Mandated state and federal standards could result in the use of renewable energy sources that are not cost-effective in order to comply with requirements. If we are not able to receive retail rates reflecting our costs or investments to comply with the state or federal standards, our financial condition and results of operation may be adversely affected.

There are inherent potential risks in the operation of nuclear facilities, including environmental, health, regulatory, terrorism, and financial risks, that could result in fines or the shutdown of our nuclear units, which may present potential financial exposures in excess of our insurance coverage .

PEC operates four nuclear units (three of which are jointly owned) and PEF jointly owns and operates one nuclear unit. In addition, we are exploring the possibility of expanding our nuclear generating capacity to meet future expected baseload generation needs. Our nuclear facilities are subject to operational, environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, maintaining adequate capital reserves for decommissioning, limitations on amounts and types of insurance available, potential operational liabilities and extended outages, and the costs of securing the facilities against possible terrorist attacks. We maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks. However, damages from an accident or business interruption at our nuclear units could exceed the amount of our insurance coverage. For PEF, it may incur liabilities to co-owners in the event of extended outages or operation at less than full capacity. If the Utilities are not allowed to recover the additional costs incurred either through insurance or regulatory mechanisms, our results of operations could be negatively impacted.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require us to make substantial expenditures at our nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

Our nuclear facilities have operating licenses that need to be renewed periodically. We anticipate successful renewal of these licenses. However, potential terrorist threats and increased public scrutiny of utilities could result in an extended process with higher licensing or compliance costs.

With the prospect of construction of a number of new nuclear facilities across the country and an aging skilled workforce, there is increased competition within the energy sector for skilled technical workers for both the construction and operation of nuclear facilities. Our ability to successfully operate our nuclear facilities is dependent upon our continued ability to recruit and retain skilled technical workers.

We are subject to numerous environmental laws and regulations that require significant capital expenditures, increase our cost of operations, and may impact or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste, and hazardous waste production, handling and disposal. These laws and regulations can result in increased capital, operating and other costs, particularly with regard to enforcement efforts focused on existing power plants and compliance plans with regard to new and existing power plants. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, authorizations and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. Failure to comply with applicable regulations and permits might result in the imposition of fines and penalties by regulatory authorities. We cannot provide assurance that existing environmental regulations will not be revised or that new environmental regulations will not be adopted or become applicable to us. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a material adverse effect on our results of operations, particularly if those costs are not fully recoverable from our ratepayers.

In addition, we may be deemed a responsible party for environmental clean-up at sites identified by a regulatory body or private party. We cannot predict with certainty the amount or timing of future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs. While we accrue for probable costs that can be reasonably estimated, not all costs can be reasonably estimated or accrued and actual costs may materially exceed our accruals. Material costs in excess of our accruals could have an adverse impact on our financial condition and results of operations.

Our coal-fired plants produce coal combustion products, primarily ash. The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products. PEC's impoundment dams are subject to additional state regulation due to a North Carolina law enacted in 2009. Until the applicable state agency inspects each of the affected dams, we cannot predict if additional safety-related measures will be required. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or additional environmental controls for groundwater protection, and future mitigation of related impacts could have a material impact on our results of operations or financial condition.

Our compliance with environmental regulations, including those to reduce emissions of NOx, SO_2 and mercury from coal-fired power plants, requires significant capital expenditures that impact our financial condition. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. These costs could be higher than currently expected and have an adverse impact on our results of operations and financial condition.

The operation of emission control equipment needed to comply with requirements set by various environmental regulations increases our operating costs and reduces the generating capacity of our coal-fired plants. O&M expenses significantly increase due to the additional personnel, materials and general maintenance associated with operation of the equipment. Operation of the emission control equipment requires the procurement of significant quantities of reagents, such as limestone and ammonia. Future increases in demand for these items from other utility companies operating similar equipment could increase our costs associated with operating the equipment. Additionally, the operation of emission control equipment may result in the development of collateral issues that require further remedial actions, resulting in additional expenditures and operating costs.

We are subject to risks associated with climate change, which could have a negative impact on our business, financial condition and results of operations. Future legislation or regulation may impose significant restrictions on CO_2 and other GHG emissions. We may incur significant costs to comply with such legislation or regulation. Physical risks associated with climate change could impact us.

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. Any future legislative or regulatory actions taken to address global climate change represent a business risk to our operations and the full impact of such initiatives on our operations cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time, for which the Utilities would seek corresponding rate recovery. Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers.

According to the Intergovernmental Panel on Climate Change, potential climate change impacts in the southeastern United States could include warmer days and nights, increased total rainfall from heavy storms, increased tropical cyclone activity, sea level rise and increased drought conditions. An increase in the number of heat waves, periods of drought and sea level rise could result in changes in energy demand due to shifting populations and industry. Destruction caused by severe weather events such as hurricanes, tornadoes, severe thunderstorms and winter storms may result in lost operating revenues due to outages, property damage and other unexpected expenses.

We could become subject to litigation related to the purported impacts of GHG emissions. A number of legal actions have been filed against other electric utilities asserting public and private nuisance, trespass and negligence claims.

Because weather conditions directly influence the demand for, our ability to provide, and the cost of providing electricity, our results of operations, financial condition and cash flows can fluctuate on a seasonal or quarterly basis and can be negatively affected by changes in weather conditions and severe weather .

Weather conditions in our service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to our customers. As a result, our future overall operating results may fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions were mild. While we believe that the Utilities' markets complement each other during normal seasonal fluctuations, unusually mild weather could diminish our results of operations and harm our financial condition.

Sustained severe drought conditions could impact generation by PEC's hydroelectric plants, as well as our fossil and nuclear plant operations, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. Furthermore, destruction caused by severe weather events, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can result in lost operating revenues due to outages; property damage, including downed transmission and distribution lines; and additional and unexpected expenses to mitigate storm damage.

Our ability to recover significant costs resulting from severe weather events is subject to regulatory oversight, and the timing and amount of any such recovery is uncertain and may impact our financial conditions.

We are subject to incurring significant costs resulting from damage sustained during severe weather events. While the Utilities have historically been granted regulatory approval to defer and amortize or collect from customers the majority of significant storm costs incurred, the Utilities' storm cost-recovery petitions may not always be granted or may not be granted in a timely manner. If we cannot recover costs associated with future severe weather events in a timely manner, or in an amount sufficient to cover our actual costs, our financial conditions and results of operations could be materially and adversely impacted.

Under a regulatory order, PEF maintains a storm damage reserve account for major storms with provisions for implementing an interim retail surcharge in the event future storms deplete the reserve and prudency reviews of storm costs by the FPSC. Storm reserve costs attributable to PEF's wholesale customers may be amortized consistent with recovery of such amounts in wholesale rates, albeit at a specified amount per year, which could result in an extended recovery period.

PEC does not maintain a storm damage reserve account and does not have an ongoing regulatory mechanism to recover storm costs. PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over five-year periods.

Our revenues, operating results and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions. We are also impacted by the demand and competitive state of the wholesale market.

Our revenues, operating results and financial condition are impacted by customer growth and usage. Customer growth can be impacted by population growth as well as by economic factors, including but not limited to, job growth and housing market trends. The Utilities are impacted by the economic cycles of the customers we serve. As our service territories experience economic downturns, residential customer consumption patterns may change and our revenues may be negatively impacted. If our commercial and industrial customers experience economic downturns, their consumption of electricity may decline and our revenues can be negatively impacted. Like other parts of the United States, our service territories and business have been impacted by the current economic conditions. The timing and extent of the recovery of the economy cannot be predicted. Additionally, our customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income or individual energy conservation efforts.

Wholesale revenues fluctuate with regional demand, fuel prices and contracted capacity. Our wholesale profitability is dependent upon market conditions and our ability to renew or replace expiring wholesale contracts on favorable terms. Based on economic conditions in effect when wholesale contracts expire, the Utilities may not be successful in renewing or replacing expiring contracts.

Fluctuations in commodity prices or availability may adversely affect various aspects of the Utilities' operations as well as the Utilities' financial condition, results of operations or cash flows .

We are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, nuclear fuel, electricity and other energy-related commodities, including emission allowances, as a result of our ownership of energy-related assets. We have hedging strategies in place to mitigate fluctuations in commodity supply prices, but to the extent that we do not cover our entire exposure to commodity price fluctuations, or our hedging procedures do not work as planned, there can be no assurances that our financial performance will not be negatively impacted by price fluctuations. Additionally, we are exposed to risk that our counterparties will not be able to perform their obligations. Should our counterparties fail to perform, we might be forced to replace the underlying commitment at prevailing market prices. In such event, we might incur losses in addition to the amounts, if any, already paid to the counterparties.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Downgrades in our credit ratings could lead to additional collateral posting requirements. We continually monitor our derivative positions in relation to market price activity.

Volatility in market prices for fuel and power may result from, among other items:

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- technological changes;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, nuclear fuel and coal production levels;
- natural disasters, wars, terrorism, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

In addition, we anticipate significant capital expenditures for environmental compliance and baseload generation. The completion of these projects within established budgets is contingent upon many variables including the securing of labor and materials at estimated costs. The demand and prices for labor and materials are subject to volatility and may increase in the future. We are subject to the risk that cost overages may not be recoverable from ratepayers and our financial condition, results of operations or cash flows may be adversely impacted.

Prices for emission allowance credits fluctuate. While allowances are eligible for annual recovery in PEF's jurisdictions in Florida and PEC's in South Carolina, no such annual recovery exists in North Carolina for PEC. Future changes in the price of allowances could have a significant adverse financial impact on us and PEC and, consequently, on our results of operations and cash flows.

As a holding company with no revenue-generating operations, the Parent is dependent on upstream cash flows from its subsidiaries, primarily the Utilities; its commercial paper and bank facilities; and its ability to access the long-term debt and equity capital markets.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's senior unsecured debt and potentially funding a portion of the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. Prior to funding the Parent, its subsidiaries have financial obligations that must be satisfied, including, among others, their respective debt service, preferred dividends and obligations to trade creditors. Additionally, the Utilities could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from the Parent. Should the Utilities not be able to pay dividends or repay funds due to the Parent or if the Parent cannot access the commercial paper market, its bank facilities or the long-term debt and equity capital markets, the Parent's ability to pay principal, interest and dividends would be restricted. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Our business is dependent on our ability to successfully access capital markets on favorable terms. Limits on our access to capital may adversely impact our ability to execute our business plan or pursue improvements that we would otherwise rely on for future growth .

Our cash requirements are driven by the capital-intensive nature of our Utilities. In addition to operating cash flows, we rely heavily on commercial paper, long-term debt and equity. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy will be adversely affected. Market disruptions or a downgrade of our credit ratings could increase our cost of borrowing and may adversely affect our ability to access the financial markets. If we cannot fund our expected capital expenditures and debt maturities through normal operations or by accessing capital markets, our business plans, financial condition, results of operations or cash flows may be adversely impacted. See discussion of our expected capital expenditures in MD&A – "Liquidity and Capital Resources – Capital Expenditures."

We issue commercial paper to meet short-term liquidity needs. When financial and economic conditions result in tightened short-term credit markets, coupled with corresponding volatility in commercial paper durations and interest rates, we evaluate other options for meeting our short-term liquidity needs, which may include borrowing from our revolving credit agreements (RCAs), issuing short-term notes, issuing long-term debt and/or issuing equity. In addition, if our short-term credit ratings are downgraded below Tier 2 (A-2/P-2/F2) we could experience increased volatility in commercial paper durations and interest rates and our access to the commercial paper markets may be negatively impacted. In that case, we would evaluate other options for meeting our short-term liquidity needs as previously described. These alternative sources of liquidity may not be available or may not have comparable favorable terms and, thus, may impact adversely our business plans, financial condition, results of operations or cash flows.

Increases in our leverage or reductions in our cash flow could adversely affect our competitive position, business planning and flexibility, financial condition, ability to service our debt obligations and to pay dividends on our common stock, and ability to access capital on favorable terms .

As discussed above, we rely heavily on our commercial paper and long-term debt. Our credit agreements contain certain provisions and impose various limitations that could impact our liquidity, such as cross-default provisions and defined maximum total debt to total capital (leverage) ratios. Under these revolving credit facilities, indebtedness includes certain letters of credit and guarantees that are not recorded on the Consolidated Balance Sheets.

As previously discussed, we are anticipating extensive capital needs for new generation, transmission and distribution facilities, and environmental compliance expenditures. Funding these capital needs could increase our leverage and present numerous risks including those addressed below.

In the event our leverage increases such that we approach the permitted ratios, our access to capital and additional liquidity could decrease. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs. Additionally, a significant increase in our leverage or reductions in cash flow could adversely affect us by:

- increasing the cost of future debt financing;
- impacting our ability to pay dividends on our common stock at the current rate;
- making it more difficult for us to satisfy our existing financial obligations;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to debt repayment, thereby reducing funds available for operations, future business opportunities or other purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete;
- requiring the issuance of additional equity;
- placing us at a competitive disadvantage compared to competitors who have less debt; and
- causing a downgrade in our credit ratings.

Any reduction in our credit ratings below investment grade would likely increase our financing costs, limit our access to additional capital and require posting of collateral, all of which could materially and adversely affect our business, results of operations and financial condition.

While the long-term target credit ratings for the Parent and the Utilities are above the minimum investment grade rating, we cannot provide certainty that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Such circumstances could include, among others, increases in leverage, adverse changes in other financial metrics, and adverse regulatory outcomes. Our debt indentures and credit agreements do not contain any “ratings triggers,” which would cause the acceleration of interest and principal payments in the event of a ratings downgrade. Any downgrade could increase our borrowing costs, may adversely affect our access to capital and could result in the posting of additional collateral for derivatives in a liability position, which could negatively impact our financial results and business plans. Any reduction in our credit ratings below investment grade could also result in collateral posting requirements for certain of our natural gas transportation contracts. We note that the ratings from credit agencies are not recommendations to buy, sell or hold our securities or those of PEC or PEF and that each agency’s rating should be evaluated independently of any other agency’s rating.

Market performance and other changes may decrease the value of nuclear decommissioning trust funds and benefit plan assets, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations to decommission the Utilities’ nuclear plants and under our defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. Although a number of factors impact our funding requirements, a decline in the market value of the assets may increase the funding requirements of the obligations for decommissioning the Utilities’ nuclear plants and under our defined benefit pension and other postretirement benefit plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, the funding requirements of the obligations related to these benefit plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or changes in life expectancy assumptions. If we are unable to successfully manage the nuclear decommissioning trust funds and benefit plan assets, our results of operation and financial position could be negatively affected.

Impairment of goodwill could have a significant negative impact on our financial condition and results of operations .

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments, and goodwill impairment tests are performed at the utility segment level.

We calculate the fair value of our utility segments by considering various factors, including valuation studies based primarily on income and market approaches. The calculations in both approaches are highly dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates from a marketplace participant's perspective, and the selection of peer utilities and marketplace transactions for comparative valuation purposes. The estimated future cash flows are based on the utility segments' business plans that assume the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, the timing of anticipated significant future capital investments, the anticipated earnings and returns related to such capital investments, continued recovery of cost of service and renewal of certain contracts. These underlying assumptions and estimates are made as of a point in time. If these assumptions change or should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, the fair value of the utility segments could be significantly different in future periods, which could result in a future impairment charge to goodwill. Impairment of our recorded goodwill could result in volatility in our GAAP earnings and an increase in our leverage, which could trigger a downgrade of our credit ratings leading to higher borrowing costs and/or dilution through additional issuances of common stock. However, in the event of a goodwill impairment, we do not expect any such impairment to cause us to violate any financial or restrictive covenants contained in our indebtedness or other contractual arrangements.

Our ability to fully utilize tax credits generated under Section 29/45K may be limited. This risk is not applicable to PEC and PEF.

In accordance with the provisions of Section 29/45K, we have generated tax credits based on the content and quantity of synthetic fuels produced and sold to unrelated parties. This tax credit program expired at the end of 2007. The timing of the utilization of the tax credits is dependent upon our taxable income, which can be impacted by a number of factors. Additionally, in the normal course of business, our tax returns are audited by the IRS. If our tax credits were disallowed in whole or in part as a result of an IRS audit, there could be significant additional tax liabilities and associated interest for previously recognized tax credits, which could have a material adverse impact on our earnings and cash flows. Although we are unaware of any currently proposed legislation or new IRS regulations or interpretations impacting previously recorded synthetic fuels tax credits, the value of credits generated could be unfavorably impacted by such legislation or IRS regulations and interpretations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

We believe that our physical properties and those of our subsidiaries are adequate to carry on our and their businesses as currently conducted. We maintain property insurance against loss or damage by fire or other perils to the extent that such property is usually insured.

ELECTRIC – PEC

PEC's 18 generating plants represent a flexible mix of fossil steam, nuclear, combustion turbines, combined cycle, and hydroelectric resources, with a total summer generating capacity of 12,585 MW. Of this total, Power Agency owns approximately 700 MW. On December 31, 2009, PEC had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEC Ownership (in %)	Summer Net Capability [a] (in MW)
FOSSIL STEAM						
Asheville	Arden, N.C.	2	1964-1971	Coal	100	376
Cape Fear [b]	Moncure, N.C.	2	1956-1958	Coal	100	316
Lee [b]	Goldsboro, N.C.	3	1951-1962	Coal	100	397
Mayo	Roxboro, N.C.	1	1983	Coal	83.83	727[c]
Robinson	Hartsville, S.C.	1	1960	Coal	100	177
Roxboro	Semora, N.C.	4	1966-1980	Coal	96.30 [d]	2,422[c]
Sutton [b]	Wilmington, N.C.	3	1954-1972	Coal	100	604
Weatherspoon [b]	Lumberton, N.C.	3	1949-1952	Coal	100	171
	Total	19				5,190
NUCLEAR						
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67	1,858[c]
Harris	New Hill, N.C.	1	1987	Uranium	83.83	900[c]
Robinson	Hartsville, S.C.	1	1971	Uranium	100	724
	Total	4				3,482
COMBUSTION TURBINES						
Asheville	Arden, N.C.	2	1999-2000	Gas/Oil	100	324
Blewett	Lilesville, N.C.	4	1971	Oil	100	52
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100	799
Lee	Goldsboro, N.C.	4	1968-1971	Oil	100	75
Morehead City	Morehead City, N.C.	1	1968	Oil	100	12
Richmond	Hamlet, N.C.	5	2001-2002	Gas/Oil	100	820
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100	15
Sutton	Wilmington, N.C.	3	1968-1969	Gas/Oil	100	61
Wayne County	Goldsboro, N.C.	5	2000-2009	Gas/Oil	100	863
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100	131
	Total	42				3,152
COMBINED CYCLE						
Cape Fear	Moncure, N.C.	2	1969	Oil	100	66
Richmond	Hamlet, N.C.	1	2002	Gas/Oil	100	470
	Total	3				536
HYDRO						
Blewett	Lilesville, N.C.	6	1912	Water	100	22
Marshall	Marshall, N.C.	2	1910	Water	100	4
Tillery	Mount Gilead, N.C.	4	1928-1960	Water	100	87
Walters	Waterville, N.C.	3	1930	Water	100	112
	Total	15				225
TOTAL		83				12,585

(a) Summer ratings reflect compliance with NERC reliability standards and are gross of joint ownership interest.
(b) PEC has announced that it intends to permanently shut-down these units between 2013 and the end of 2017. See Item 1 – "PEC – Fuel and Purchased Power – Oil and Gas" regarding PEC's plans to build new generation fueled by natural gas.
(c) Facilities are jointly owned by PEC and Power Agency. The capacities shown include Power Agency's share.
(d) PEC and Power Agency are joint owners of Unit 4 at the Roxboro Plant. PEC's ownership interest in this 698-MW unit is 87.06 percent.

At December 31, 2009, including both the total generating capacity of 12,585 MW and the total firm contracts for purchased power of 1,309 MW, PEC had total capacity resources of approximately 13,894 MW.

Power Agency has undivided ownership interests of 18.33 percent in Brunswick Unit Nos. 1 and 2, 12.94 percent in Roxboro Unit No. 4, 3.77 percent in Roxboro Common facilities, and 16.17 percent in Harris and Mayo Unit No. 1. Otherwise, PEC has good and marketable title to its principal plants and units, subject to the lien of its mortgage and deed of trust, with minor exceptions, restrictions, and reservations in conveyances, as well as minor defects of the nature ordinarily found in properties of similar character and magnitude. PEC also owns certain easements over private property on which transmission and distribution lines are located.

At December 31, 2009, PEC had approximately 6,000 circuit miles of transmission lines including 300 miles of 500 kilovolt (kV) lines and 3,000 miles of 230 kV lines. PEC also had approximately 45,000 circuit miles of overhead distribution conductor and 22,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 55 million kilovolt-ampere (kVA) in approximately 900 transformers. Distribution line transformers numbered approximately 538,000 with an aggregate capacity of approximately 24 million kVA.

ELECTRIC – PEF

PEF's 14 generating plants represent a flexible mix of fossil steam, combustion turbine, combined cycle, and nuclear resources, with a total summer generating capacity of 10,013 MW. Of this total, joint owners own approximately 120 MW. At December 31, 2009, PEF had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEF Ownership (in %)	Summer Net Capability [a] (in MW)
FOSSIL STEAM						
Anclote	Holiday, Fla.	2	1974-1978	Gas/Oil	100	1,011
Crystal River	Crystal River, Fla.	4	1966-1984	Coal	100	2,267
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	131
	Total	9				3,409
COMBINED CYCLE						
Bartow	St. Petersburg, Fla.	1	2009	Gas/Oil	100	1,133 [b]
Hines	Bartow, Fla.	4	1999-2007	Gas/Oil	100	1,912
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	205
	Total	6				3,250
COMBUSTION TURBINES						
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	48
Bartow	St. Petersburg, Fla.	4	1972	Gas/Oil	100	178
Bayboro	St. Petersburg, Fla.	4	1973	Oil	100	174
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	642
Higgins	Oldsmar, Fla.	4	1969-1971	Gas/Oil	100	114
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	[c]	980 [d]
Rio Pinar	Rio Pinar, Fla.	1	1970	Oil	100	12
Suwannee River	Live Oak, Fla.	3	1980	Gas/Oil	100	153
Turner	Enterprise, Fla.	4	1970-1974	Oil	100	147
University of Florida Cogeneration	Gainesville, Fla.	1	1994	Gas	100	46
	Total	47				2,494
NUCLEAR						
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	860 [d]
	Total	1				860
TOTAL		63				10,013

[a] Summer ratings reflect compliance with NERC reliability standards and are gross of joint ownership interest.
[b] This facility, which had a summer net capacity of 426 MW in 2008, was converted from fossil steam to combined cycle and returned to commercial operations in June 2009.
[c] PEF and Georgia Power Company are joint owners of a 143 MW advanced combustion turbine located at PEF's Intercession City site. Georgia Power Company has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year.
[d] Facilities are jointly owned. The capacities shown include joint owners' share.

During 2009, including both the total generating capacity of 10,013 MW and the total firm contracts for purchased power of 1,847 MW, PEF had total capacity resources of approximately 11,860 MW.

Several entities have acquired undivided ownership interests in CR3 in the aggregate amount of 8.22 percent. The joint ownership participants are: City of Alachua – 0.08 percent, City of Bushnell – 0.04 percent, City of Gainesville – 1.41 percent, Kissimmee Utility Authority – 0.68 percent, City of Leesburg – 0.82 percent, Utilities Commission of the City of New Smyrna Beach – 0.56 percent, City of Ocala – 1.33 percent, Orlando Utilities Commission – 1.60 percent and Seminole Electric Cooperative, Inc. – 1.70 percent. PEF and Georgia Power Company are co-owners of a 143 MW advance combustion turbine located at PEF's Intercession City Unit P11. Georgia Power Company has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year. Otherwise, PEF has good and marketable title to its principal plants and units, subject to the lien of its mortgage and deed of trust, with minor exceptions, restrictions and reservations in conveyances, as well as minor defects of the nature ordinarily found in properties of similar character and magnitude. PEF also owns certain easements over private property on which transmission and distribution lines are located.

At December 31, 2009, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and approximately 1,500 miles of 230 kV lines. PEF also had approximately 18,000 circuit miles of overhead distribution conductor and 13,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 54 million kVA in approximately 800 transformers. Distribution line transformers numbered approximately 390,000 with an aggregate capacity of approximately 20 million kVA.

ITEM 3. LEGAL PROCEEDINGS

Legal proceedings are included in the discussion of our business in PART I, Item 1 under "Environmental," and are incorporated by reference herein. See Note 22D for a discussion of certain other legal matters.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

The information called for by Item 4 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

EXECUTIVE OFFICERS OF THE REGISTRANTS AT FEBRUARY 22, 2010

Name	Age	Recent Business Experience
William D. Johnson	56	**Chairman, President and Chief Executive Officer, Progress Energy and Florida Progress,** October 2007 to present; **Chairman, PEC and PEF,** from November 2007 to present; President and Chief Operating Officer, Progress Energy, from January 2005 to October 2007; Group President, PEC, from January 2004 to October 2007; Executive Vice President, PEF, from November 2000 to November 2007; Executive Vice President, Florida Progress, from November 2000 to December 2003; and Corporate Secretary, PEC, PEF, Progress Energy Service Company, LLC and Florida Progress, from November 2000 to December 2003. Mr. Johnson has been with Progress Energy (formerly CP&L) since 1992 and served as Group President, Energy Delivery, Progress Energy, from January 2004 to December 2004. Prior to that, he was President, CEO and Corporate Secretary, Progress Energy Service Company, LLC, from October 2002 to December 2003. He also served as Executive Vice President – Corporate Relations & Administrative Services, General Counsel and Secretary of Progress Energy. Mr. Johnson served as Vice President – Legal Department and Corporate Secretary, CP&L, from 1997 to 1999. Before joining Progress Energy, Mr. Johnson was a partner with the Raleigh, N.C. office of Hunton & Williams LLP where he specialized in the representation of utilities. He previously served as a law clerk to the Honorable J. Dickson Phillips Jr. of the U.S. Court of Appeals for the Fourth Circuit.

Jeffrey A. Corbett	50	**Senior Vice President, Energy Delivery, PEC,** January 2008 to present. Mr. Corbett oversees operations and services in the Carolinas, including engineering, distribution, construction, metering, power restoration, community relations and customer service. He previously served as Senior Vice President, Energy Delivery, PEF, from June 2006 to January 2008, with the same responsibilities in Florida as mentioned above. He served as Vice President – Distribution for PEC, from January 2005 to June 2006. He also served PEC as Vice President – Eastern Region, from September 2002 to January 2005. Mr. Corbett joined Progress Energy in 1999 and has served in a number of roles, including General Manager of the Eastern Region and director of Distribution Power Quality and Reliability. Before joining Progress Energy, Mr. Corbett spent 17 years with Virginia Power, serving in a variety of engineering and leadership roles.
*Vincent M. Dolan	55	**President and Chief Executive Officer, PEF,** July 2009 to present. Mr. Dolan oversees all aspects of PEF's delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Vice President – External Relations, PEF, from December 2006 to July 2009; Vice President – R egulatory & Customer Relations, PEF, from March 2005 to December 2006; and Vice President – Corporate Relations & Administrative Services, PEF, from April 2002 to March 2005. Mr. Dolan has been with PEF since 1986 in positions of increasing responsibility in the areas of operations, strategic development, customer services, and regulatory affairs. Prior to that, he was with Foster Wheeler Energy Corporation, an international engineering and manufacturing firm.
*Michael A. Lewis	47	**Senior Vice President, Energy Delivery, PEF,** January 2008 to present. Mr. Lewis oversees operations and services in Florida, including engineering, distribution, construction, metering, power restoration, community relations, energy-efficiency, and alternative energy strategies. He previously served as Vice President, Distribution, PEF, from August 2007 to January 2008, Vice President, Distribution Engineering & Operations, PEF, from December 2005 to August 2007, Vice President, Distribution Operations & Support, PEF, from April 2004 to December 2005 and Vice President, Coastal Region, PEF, from December 2000 to April 2004. Mr. Lewis has been with PEF in a number of engineering and management positions since 1986, including District Manager, Distribution Operations Manager in Pasco County, General Manager for the South Coastal region and Regional Vice President of both the North and South Coastal regions.
Jeffrey J. Lyash	48	**Executive Vice President, Corporate Development, Progress Energy,** July 2009 to present. In his role, Mr. Lyash is responsible for Progress Energy's resource planning, program alternatives, and strategic asset construction. He previously served as President and Chief Executive Officer, PEF, from June 2006 to July 2009; Senior Vice President, PEF, from November 2003 to June 2006; and Vice President – Transmission in Energy Delivery, PEC, from January 2002 to October 2003. Mr. Lyash joined Progress Energy (formerly CP&L) in 1993 and spent his first eight years at the Brunswick Nuclear Plant in Southport, N.C. His last position at Brunswick was as Director of site operations. Before joining Progress Energy, Mr. Lyash worked with the U.S. Nuclear Regulatory Commission (NRC) in a number of capacities between 1984 and 1993.

John R. McArthur	54	**Executive Vice President, Progress Energy,** September 2008 to present. In his various roles, Mr. McArthur is responsible for corporate and utility support functions, including Corporate Services, Corporate Communications, External Relations, Human Resources and Information Technology and Telecommunications. The compliance, legal and audit functions are also part of his group. He also serves as Corporate Secretary of Progress Energy, a position he has held since January 2004. Mr. McArthur is also Executive Vice President of PEC since September 2008, Executive Vice President of PEF since November 2008 and Executive Vice President of Florida Progress Corporation since January 2010. Mr. McArthur has been with Progress Energy in a number of roles since 2001, including General Counsel, Senior Vice President, Corporate Relations and Vice President, Public Affairs. Before joining Progress Energy, Mr. McArthur was a senior adviser to N.C. Governor Mike Easley, handling major policy initiatives as well as media and legal affairs. Previously, he handled state government affairs for General Electric Co. He also served as chief counsel in the N.C. Attorney General's office, where he supervised utility, consumer, health care, and environmental protection issues. Prior to that Mr. McArthur was a partner with the Raleigh, N.C. office of Hunton & Williams LLP and served as a law clerk to the Honorable Sam J. Ervin III of the U.S. Court of Appeals for the Fourth Circuit.
Mark F. Mulhern	50	**Senior Vice President and Chief Financial Officer, Progress Energy, PEC and PEF,** September 2008 to present. He previously served as Senior Vice President, Finance, PEC and PEF, from November 2007 to September 2008, and Senior Vice President, Finance, Progress Energy, from July 2007 to September 2008. Mr. Mulhern also served as President of Progress Ventures (the unregulated subsidiary of Progress Energy), from 2005 to 2008; Senior Vice President of Competitive Commercial Operations of Progress Ventures, from 2003 to 2005; Vice President, Strategic Planning of Progress Energy, from 2000 to 2003; Vice President and Treasurer of Progress Energy, from 1997 to 2000; and Vice President and Controller of Progress Energy, from 1996 to 1997. Before joining Progress Energy (formerly CP&L) in 1996, Mr. Mulhern was the Chief Financial Officer at Hydra Co Enterprises, the independent power subsidiary of Niagara Mohawk. He also spent eight years at Price Waterhouse, serving a wide variety of manufacturing and service businesses.
James Scarola	53	**Senior Vice President and Chief Nuclear Officer, PEC and PEF** , January 2008 to present. Mr. Scarola oversees all aspects of our nuclear program. He previously served as Vice President at the Brunswick Nuclear Plant from October 2005 to December 2007. Mr. Scarola joined Progress Energy (formerly CP&L) in 1998, where he served as Vice President at the Harris Nuclear Power Plant until October 2005. Mr. Scarola entered the nuclear power field in 1978 as a design engineer and has held positions in construction, start-up testing, maintenance, engineering and operations. He was the Plant General Manager at the St. Lucie Nuclear Plant with Florida Power & Light Company prior to joining Progress Energy.

Frank A. Schiller	48	**Senior Vice President, Compliance and General Counsel, Progress Energy,** January 2009 to present. Mr. Schiller is responsible for Progress Energy's legal, regulatory, compliance, audit and corporate governance functions. He serves as Progress Energy's chief compliance officer and chairs Progress Energy's Ethics Committee. Mr. Schiller joined Progress Energy in 1997 and previously served as Vice President, Legal, from December 2000 to December 2008; Director – Legal Services, from January 2000 to December 2000; and Associate General Counsel, from December 1997 to January 2000. Before joining Progress Energy, Mr. Schiller was Senior Counsel at Virginia Electric and Power Company. Previously, he was a partner with the Raleigh, N.C., office of Hunton & Williams LLP.
Paula J. Sims	48	**Senior Vice President, Power Operations, PEC and PEF,** July 2007 to present. Ms. Sims oversees fossil generation, new generation and transmission construction, environmental compliance, non-nuclear fuel procurement and transportation, purchased power and excess generation sales. In addition, she is responsible for leading Progress Energy's enterprise-wide Continuous Business Excellence efforts. Ms. Sims previously served as Senior Vice President, Regulated Services from January 2006 to July 2007; Vice President, Fossil Fuel Generation of Progress Energy and PEF, from January 2006 to April 2006; Vice President, Regulated Fuels of Progress Energy, from December 2004 to December 2005; Chief Operating Officer of Progress Fuels Corporation, from February 2002 to December 2004; and Vice President, Business Operations & Strategic Planning of Progress Fuels Corporation, from June 2001 to February 2002. Before joining Progress Energy in 1999, Ms. Sims was with General Electric, where she served in a number of management and operations positions for over 15 years.
Jeffrey M. Stone	48	**Chief Accounting Officer and Controller, Progress Energy and Florida Progress,** June 2005 to present; Chief Accounting Officer, PEC and PEF, from June 2005 and November 2005, respectively, to present; and Vice President and Controller, Progress Energy Service Company, LLC, from January 2005 and June 2005, respectively to present. Mr. Stone previously served as Controller of PEF and PEC, from June 2005 to November 2005. Since 1999, Mr. Stone has served Progress Energy in a number of roles in corporate support including Vice President – Capital Planning and Control; and Executive Director – Financial Planning & Regulatory Services, as well as in various management positions with Energy Supply and Audit Services. Prior to joining Progress Energy, Mr. Stone worked as an auditor with Deloitte & Touche in Charlotte, N.C.

Lloyd M. Yates	49	**President and Chief Executive Officer, PEC,** July 2007 to present. Mr. Yates oversees all aspects of PEC's delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Senior Vice President, PEC, from January 2005 to July 2007, where he was responsible for overseeing the four operational and customer service regions in the Carolinas, as well as the distribution function. He served PEC as Vice President – Transmission, from November 2003 to December 2004 and as Vice President – Fossil Generation, from November 1998 to November 2003. Before joining Progress Energy (formerly CP&L) in 1998, Mr. Yates was with PECO Energy for over 16 years in several line operations and management positions.

*Indicates individual is an executive officer of Progress Energy, Inc., but not PEC.

PART II

ITEM 5. MARKET FOR THE REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

PROGRESS ENERGY

Progress Energy's Common Stock is listed on the New York Stock Exchange under the symbol PGN. The high and low intra-day stock sales prices for each quarter for the past two years, and the cash dividends declared per share are as follows:

	High	Low	Dividends Declared
2009			
First Quarter	**$ 40.85**	**$ 31.35**	**$ 0.620**
Second Quarter	**38.20**	**33.50**	**0.620**
Third Quarter	**40.05**	**35.97**	**0.620**
Fourth Quarter	**42.20**	**36.67**	**0.620**
2008			
First Quarter	$ 49.16	$ 40.54	$ 0.615
Second Quarter	43.58	41.00	0.615
Third Quarter	45.52	40.11	0.615
Fourth Quarter	45.60	32.60	0.620

The December 31 closing price of our Common Stock was $41.01 for 2009 and $39.85 for 2008. At February 22, 2010, we had 53,922 holders of record of Common Stock.

Progress Energy expects to continue its policy of paying regular cash dividends; however, dividends are subject to declaration by the Board of Directors and the existing common stock dividend policy could change based upon business factors, including future earnings, capital requirements, and financial condition.

Neither Progress Energy's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. Our subsidiaries have provisions restricting dividends in certain limited circumstances (See Notes 9 and 11B).

Information regarding securities authorized for issuance under our equity compensation plans is included in Progress Energy's definitive proxy statement for its 2010 Annual Meeting of Shareholders.

(a) Recent Sales of Unregistered Securities; Use of Proceeds from Registered Securities.

RESTRICTED STOCK UNIT AWARD PAYOUTS:

(1) Securities Delivered. On October 5, 2009, 1,772 shares, of our common stock were delivered to a former employee pursuant to the terms of the Progress Energy 2002 and 2007 Equity Incentive Plans (individually and collectively, the "EIP,"), which have been approved by Progress Energy's shareholders. Additionally, on November 27, 2009, 3,142 shares of our common stock were delivered to the estate of a former employee pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(2) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(3) Consideration. The restricted stock unit awards were granted to provide an incentive to the former and current employees to exert their utmost efforts on Progress Energy's behalf and thus enhance our performance while aligning the employees' interest with those of our shareholders.

(4) Exemption from Registration Claimed. The common shares described in this Item were delivered pursuant to a broad-based involuntary, non-contributory employee benefit plan, and thus did not involve an offer to sell or sale of securities within the meaning of Section 2(3) of the Securities Act of 1933. Receipt of the shares of our common stock required no investment decision on the part of the recipient.

PERFORMANCE SHARE SUB-PLAN AWARD PAYOUTS:

(1) Securities Delivered. On November 27, 2009, 7,650 shares of our common stock were delivered to the estate of a former employee pursuant to the terms of the EIP. The shares of common stock delivered pursuant to the EIP were newly issued shares of Progress Energy.

(2) Underwriters and Other Purchasers. No underwriters were used in connection with the delivery of our common stock described above.

(3) Consideration. The performance share awards were granted to provide an incentive to the former employee to exert his utmost efforts on our behalf and thus enhance our performance while aligning the employee's interests with those of our shareholders.

(4) Exemption from Registration Claimed. The common shares described in this Item were delivered pursuant to a broad-based involuntary, non-contributory employee benefit plan, and thus did not involve an offer to sell or sale of securities within the meaning of Section 2(3) of the Securities Act of 1933. Receipt of the shares of our common stock required no investment decision on the part of the recipient.

(b) Purchases of Equity Securities by the Issuer adn Affiliated Purchasers.

Issuer purchases of equity securities for fourth quarter of 2009 are as follows:

Period	(a) Total Number of Shares (or Units) Purchased (1) (2) (3) (4)	(b) Average Price Paid Per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (1)
October 1 – October 31	787,147	$37.9369	N/A	N/A
November 1 – November 30	95,409	37.2923	N/A	N/A
December 1 – December 31	25,700	41.2084	N/A	N/A
Total	908,256	$37.9618	N/A	N/A

(1) At December 31, 2009, Progress Energy did not have any publicly announced plans or programs to purchase shares of its common stock.
(2) The plan administrator purchased 667,277 shares of our common stock in open-market transactions to meet share delivery obligations under the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) (See Note 9B).
(3) The plan administrator purchased 240,250 shares of our common stock in open-market transactions to meet share delivery obligations under the Savings Plan for Employees of Florida Progress Corporation (See Note 9B).
(4) During the fourth quarter of 2009, 729 shares of our common stock were withheld to pay taxes due upon the payout of certain Restricted Stock Unit awards and Performance Share Sub-Plan awards pursuant to the terms of our 2002 and 2007 Equity Incentive Plans.

PEC

Since 2000, the Parent has owned all of PEC's common stock, and as a result there is no established public trading market for the stock. PEC has neither issued nor repurchased any equity securities since becoming a wholly owned subsidiary of the Parent. During 2009 and 2007, PEC paid dividends to the Parent totaling the amounts shown in PEC's Statements of Common Equity included in the financial statements in PART II, Item 8. During 2008, PEC paid no dividends to the Parent. PEC has provisions restricting dividends in certain circumstances (See Notes 9 and 11). PEC does not have any equity compensation plans under which its equity securities are issued.

PEF

All shares of PEF's common stock are owned by Florida Progress and as a result there is no established public trading market for the stock. PEF has neither issued nor repurchased any equity securities since becoming an indirect subsidiary of the Parent. During 2009, 2008 and 2007, PEF paid no dividends to Florida Progress. PEF has provisions restricting dividends in certain circumstances (See Notes 9 and 11). PEF does not have any equity compensation plans under which its equity securities are issued.

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data should be read in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this report.

PROGRESS ENERGY

	Years Ended December 31				
(in millions, except per share data)	**2009**	2008 [a]	2007 [a]	2006 [a]	2005 [a]
OPERATING RESULTS					
Operating revenues	**$ 9,885**	$ 9,167	$ 9,153	$ 8,724	$ 7,948
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**840**	778	702	567	527
Net income	**761**	836	496	620	668
Net income attributable to controlling interests	**757**	830	504	571	697
PER SHARE DATA [b]					
Basic and diluted earnings					
Income from continuing operations attributable to controlling interests, net of tax	**$ 2.99**	$ 2.95	$ 2.70	$ 2.19	$ 2.10
Net income attributable to controlling interests	**2.71**	3.17	1.96	2.27	2.80
ASSETS	**$ 31,236**	$ 29,873	$ 26,338	$ 25,832	$ 27,083
CAPITALIZATION AND DEBT					
Common stock equity	**$ 9,449**	$ 8,687	$ 8,395	$ 8,259	$ 8,011
Noncontrolling interests	**6**	6	84	10	36
Preferred stock of subsidiaries	**93**	93	93	93	93
Long-term debt, net [c]	**12,051**	10,659	8,737	8,835	10,446
Current portion of long-term debt	**406**	–	877	324	513
Short-term debt	**140**	1,050	201	–	175
Capital lease obligations	**231**	239	247	72	18
Total capitalization and debt	**$ 22,376**	$ 20,734	$ 18,634	$ 17,593	$ 19,292
Dividends declared per common share	**$ 2.480**	$ 2.465	$ 2.445	$ 2.425	$ 2.375

[a] Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

[b] Balances have been restated for the adoption of new accounting guidance, which redefined which securities and non-vested share-based compensation awards are considered to participate in our current earnings (See Note 2).

[c] Includes long-term debt to affiliated trust of $272 million at December 31, 2009 and 2008, $271 million at December 31, 2007 and 2006 and $270 million at December 31, 2005 (See Note 23).

PEC

(in millions)	Years Ended December 31 2009	2008 [a]	2007 [a]	2006 [a]	2005 [a]
OPERATING RESULTS					
Operating revenues	**$ 4,627**	$ 4,429	$ 4,385	$ 4,086	$ 3,991
Net income	**514**	534	501	457	493
Net income attributable to controlling interests	**516**	534	501	457	493
Net income available to parent	**513**	531	498	454	490
ASSETS	**$ 13,502**	$ 13,165	$ 11,955	$ 11,999	$ 11,471
CAPITALIZATION AND DEBT					
Common stock equity	**$ 4,657**	$ 4,301	$ 3,752	$ 3,363	$ 3,091
Noncontrolling interests	**3**	4	4	4	5
Preferred stock	**59**	59	59	59	59
Long-term debt, net	**3,703**	3,509	3,183	3,470	3,667
Current portion of long-term debt	**6**	–	300	200	–
Short-term debt [b]	–	110	154	–	84
Capital lease obligations	**15**	16	17	18	18
Total capitalization and debt	**$ 8,443**	$ 7,999	$ 7,469	$ 7,114	$ 6,924

[a] Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).
[b] Includes notes payable to affiliated companies, related to the money pool program, of $–, $154 million and $11 million at December 31, 2008, 2007 and 2005, respectively.

PEF

The information called for by Item 6 is omitted for PEF pursuant to Instruction I(2)(a) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is separately filed by Progress Energy, Inc. (Progress Energy), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF). As used in this report, Progress Energy, which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "us" or "our." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. Information contained herein relating to PEC and PEF individually is filed by such company on its own behalf. Neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

MD&A contains forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

MD&A includes financial information prepared in accordance with accounting principles generally accepted in the United States of America (GAAP), as well as certain non-GAAP financial measures, "Ongoing Earnings" and "Base Revenues," discussed below. Generally, a non-GAAP financial measure is a numerical measure of financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The non-GAAP financial measures should be viewed as a supplement to and not a substitute for financial measures presented in accordance with GAAP. Non-GAAP measures as presented herein may not be comparable to similarly titled measures used by other companies.

MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements. Certain amounts for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

PROGRESS ENERGY

INTRODUCTION

Our reportable business segments are PEC and PEF, and their primary operations are the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. The "Corporate and Other" segment primarily includes the operations of the Parent, Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative requirements as a separate reportable business segment.

STRATEGY

We are an integrated energy company primarily focused on the end-use electricity markets. We own two electric utilities that operate in regulated retail utility markets in North Carolina, South Carolina and Florida and have access to attractive wholesale markets in the eastern United States. The Utilities have more than 22,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

We have a strong track record of meeting our financial commitments and delivering operational excellence. We have maintained liquidity and financial stability and sustained our dividend rate during the current economic downturn, and we believe that we have good prospects for growth once the economy begins to recover. An improving national economy may lead to greater mobility for homeowners around the country and a return of migration to the Southeast region that is more consistent with historical levels. The utility industry, as a whole, however, faces significant cost pressures and, in the near-term, lower retail electricity sales. In addition, current economic conditions and anticipated higher expenditures (including for environmental compliance, renewable energy standards compliance and new generation and transmission facilities) may subject us to an even higher level of scrutiny from regulators and lead to a more uncertain regulatory environment. We anticipate the need to prepare for a different kind of energy future – one that would include, among other things, reducing carbon emissions and using emerging technologies such as the Smart Grid and electric vehicles. We believe that our balanced solution strategy provides an effective, flexible framework to prepare for this new energy future. Additional information about the strategy, including updates on implementation, is included in "Strategic Initiatives" below.

To manage the challenges of the present and prepare for the future, management's priority focus areas for 2010 and beyond are as follows:

- Financial Performance
- Operational Performance
- Organizational Effectiveness
- Regulation and Public Policy
- Strategic Initiatives

The first two priorities are core elements of managing our business. The next two priorities will help enable what we can accomplish in the future. The last priority involves making the right investments to create a strong energy future for Progress Energy and our customers.

FINANCIAL AND OPERATIONAL PERFORMANCE

Effectively managing expenses, deploying capital and enhancing our margin are critical to achieving sustainable earnings growth and attractive long-term returns for our shareholders. We have instituted throughout our organization systematic approaches to achieve sustainable cost savings through enhanced efficiency and productivity. These ongoing cost management initiatives – along with short-term expense management – have enabled us to offset some of the impact of the economic downturn and cost pressures and should yield long-term operations and maintenance (O&M) expense savings and effective capital management. Also, we recognize that our shareholders strongly value our dividend and that it is an integral part of our total shareholder return proposition. Our long-term goal is to achieve a 70 to 75 percent dividend payout ratio, and we are committed to managing the company such that we reach this target while maintaining an attractive, sustainable dividend rate.

Our financial performance depends on the successful operation of the Utilities' electric generating and distribution facilities and reliable delivery of electric service to our customers. Consequently, we strive to excel in safety, operational performance and customer satisfaction. We also focus on rigorous project management in executing our capital program, including large-scale capital projects such as construction of new generating facilities, modernization of existing facilities and environmental compliance as well as programs such as demand-side management (DSM).

Another operational priority is a fleet alignment initiative to strengthen the Utilities' nuclear performance in safely and reliably producing electricity while meeting the highest standards of environmental protection in the most efficient manner. The multi-year initiative implements a new business model for our five nuclear units and is based on industry benchmarking that coordinated, collaborative and standardized operations achieves and sustains a higher level of performance than would be possible if each unit operated autonomously. The goals of the initiative are, among other things, to establish a common vision and set of core values; facilitate common procedures across the fleet to accommodate shared resources and industry best practices; and establish a strong performance-monitoring system that provides feedback to management.

ORGANIZATIONAL EFFECTIVENESS

With our managers and supervisors at all levels, we emphasize demonstrating the leadership behaviors that fully engage our workforce and optimize their performance in executing our strategy. We strive to cultivate an inclusive work environment in which we treat everyone with respect and hold each other to high standards. In addition, we are implementing long-term workforce strategies to prepare for our changing needs and an aging workforce. Our workforce strategy includes recruiting, training and retaining a skilled, diverse workforce that reflects the communities we serve.

REGULATION AND PUBLIC POLICY

PEC and PEF are regulated by the state utility commissions in their state jurisdictions. Our regulatory strategy is based on filing reasonable rate requests designed to provide recovery of prudent expenses and a fair return on utility investments. Our business plans include the assumption that the respective public utility commissions will provide reasonable recovery. In 2009, PEC received approval for its coal-to-gas fleet modernization plan discussed in “Strategic Initiatives” as well as multiple DSM, renewable energy and energy-efficiency filings. Also in 2009, PEF successfully sought interim and limited rate relief and nuclear cost recovery in Florida. However, in response to a 2009 base rate case PEF filed with the Florida Public Service Commission (FPSC), in January 2010, the FPSC decided to grant PEF no increase in base rates above what was previously awarded in 2009 for the repowered Bartow Plant (approximately $132 million annual revenue requirements). The FPSC’s decision was predicated on its desire to hold down rates. However, we believe the PEF revenue level approved in January 2010 is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF’s right by law to a reasonable opportunity to recover its operating costs and return on invested capital. We are currently reviewing our regulatory options in Florida. We believe that the FPSC’s regulatory action was strongly influenced by the current economic downturn. In a long-term view of Florida’s regulatory environment, we believe that as the economy improves, the need to provide for Florida’s energy future will have a stronger influence in the FPSC’s decision-making process. Consequently, we do not believe the January 2010 decision represents a permanent change to the regulatory environment in Florida.

We are subject to significant federal and state regulations regarding air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. Changes in federal and state regulation are currently under consideration for, among others, greenhouse gases (GHG) such as carbon dioxide (CO_2), coal combustion products, mercury and particulate matter. With the state, federal and international focus on global climate change, we are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. However, we anticipate that it could result in significant rate increases over time to recover the compliance costs.

We are dedicated to seeking achievable, affordable climate and energy policies. We evaluate public policy proposals and actively promote initiatives that are achievable but manage the long-term costs to our customers.

STRATEGIC INITIATIVES

Our balanced solution strategy is intended to deploy capital effectively to meet future customer needs and emerging public policies while achieving our financial objectives. It is a three-pronged strategy that focuses on energy efficiency, alternative energy and state-of-the-art power generation. Expenditures to achieve our balanced solution should be recoverable under base rates or cost-recovery mechanisms implemented by our state jurisdictions. Updates on our implementation of this strategy are discussed below.

First, we are expanding and enhancing our DSM, energy-efficiency and energy conservation programs. We have implemented expanded energy-efficiency programs to our customers and continue to pursue additional initiatives. Federal law enacted in 2009 contains provisions promoting energy efficiency and renewable energy and we have been notified of our selection for Smart Grid grant negotiations.

Second, we are actively engaged in a variety of alternative energy projects. We have executed contracts to purchase approximately 320 MW of electricity generated from solar, biomass and municipal solid waste sources. While this currently represents a small percentage of our total capacity, we will continue to pursue additional contracts for these and other alternative energy sources.

Third, we are evaluating new generation and fleet upgrades to meet the anticipated demand at both PEC and PEF toward the end of the next decade. We are evaluating modernization of existing coal plants and the best new generation options, including advanced design nuclear technology and gas-fired combined cycle and combustion turbines. In 2009, we completed the repowering of PEF’s Bartow Plant, construction of a new 157-MW combustion turbine at PEC and the installation of pollution control equipment (or scrubbers) on PEF's coal-fired unit, Crystal River Unit No. 5 (CR5), and PEC's Mayo Plant. We also received approval to construct a 600-MW combined cycle dual-fuel facility and a 950-MW combined cycle natural gas-fueled facility at PEC, which are expected to come online in 2011 and 2013, respectively. PEC has filed for approval to construct a 620-MW natural gas-fueled facility. In 2009, we also announced our intention to embark on a major coal-to-gas fleet modernization in North Carolina by retiring approximately 1,500 MW of older coal-fired units by the end of 2017 and building combined-cycle gas. This will provide rate base growth while reducing our carbon emissions.

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. In 2008, the Utilities each filed a combined license (COL) application with the Nuclear Regulatory Commission (NRC) for two additional reactors each at Shearon Harris Nuclear Plant (Harris) and at a greenfield site in Levy County, Florida (Levy).

We have focused on Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions, as well as existing state legislative policy that is supportive of nuclear projects. PEF has received two of the three key approvals (with the issuance of a COL remaining) and entered into an engineering, procurement and construction (EPC) agreement for the two proposed Levy units. In light of a regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan with respect to Levy.

In summary, we are effectively dealing with today's challenges while taking steps to create long-term value for our customers and shareholders.

RESULTS OF OPERATIONS

In this section, we provide analysis and discussion of earnings and the factors affecting earnings on both a GAAP and non-GAAP basis. We introduce our results of operations in an overview section followed by a more detailed analysis and discussion by business segment.

A reconciliation of "Ongoing Earnings" to GAAP net income attributable to controlling interests is below, followed by an explanation of our non-GAAP financial measurement, "Ongoing Earnings."

For the year ended December 31, 2009 (in millions, except per share data)	**PEC**	**PEF**	**Corporate and Other**	**Total**	**Per Share**
Ongoing Earnings	**$ 540**	**$ 460**	**$ (154)**	**$ 846**	**$ 3.03**
CVO mark-to-market	**–**	**–**	**19**	**19**	**0.07**
Impairment, net of tax [a]	**–**	**–**	**(2)**	**(2)**	**(0.01)**
Plant retirement charge, net of tax [a]	**(17)**	**–**	**–**	**(17)**	**(0.06)**
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax [a]	**(10)**	**–**	**–**	**(10)**	**(0.04)**
Discontinued operations attributable to controlling interests, net of tax	**–**	**–**	**(79)**	**(79)**	**(0.28)**
Net income (loss) attributable to controlling interests [b]	**$ 513**	**$ 460**	**$ (216)**	**$ 757**	**$ 2.71**

For the year ended December 31, 2008 (in millions, except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
Ongoing Earnings	$ 531	$ 383	$ (138)	$ 776	$ 2.96
Valuation allowance and related net operating loss carry forward	–	–	(3)	(3)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	57	57	0.22
Net income (loss) attributable to controlling interests [b]	$ 531	$ 383	$ (84)	$ 830	$ 3.17

For the year ended December 31, 2007 (in millions, except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
Ongoing Earnings	$ 498	$ 315	$ (118)	$ 695	$ 2.71
CVO mark-to-market	–	–	(2)	(2)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	(189)	(189)	(0.74)
Net income (loss) attributable to controlling interests [b]	$ 498	$ 315	$ (309)	$ 504	$ 1.96

(a) Calculated using assumed tax rate of 40 percent.
(b) Net income attributable to controlling interests is shown net of preferred stock dividend requirement of $(3) million and $(2) million at PEC and PEF, respectively.

Management uses the non-GAAP financial measure Ongoing Earnings (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; (iii) as a measure for determining levels of incentive compensation; and (iv) in communications with our board of directors, employees, shareholders, analysts and investors concerning our financial performance. Management believes this non-GAAP measure is appropriate for understanding the business and assessing our potential future performance, because excluded items are limited to those that management believes are not representative of our fundamental core earnings. We compute Ongoing Earnings as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Historically, Ongoing Earnings for our reportable segments, which are PEC and PEF, have been consistent with the most comparable GAAP measure, net income attributable to controlling interests. In 2009, PEC recorded charges that management determined should be excluded from PEC's Ongoing Earnings. The charges were related to its planned retirement of certain coal-fired generating units prior to the end of their useful lives and a cumulative prior period adjustment related to certain employee life insurance benefits. The prior period adjustment, which was recorded in the fourth quarter of 2009, is not material to previously issued or current period financial statements. Ongoing Earnings is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to, and not a substitute for, our results of operations presented in accordance with GAAP.

OVERVIEW

FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

For the year ended December 31, 2009, our net income attributable to controlling interests was $757 million, or $2.71 per share, compared to $830 million, or $3.17 per share, for the same period in 2008. The decrease as compared to prior year was due primarily to:

- unfavorable impact of discontinued non-utility businesses (Ongoing Earnings adjustment);
- unfavorable net retail customer growth and usage at the Utilities;
- higher interest expense; and
- higher base depreciation and amortization at the Utilities.

Partially offsetting these items were:

- net impact of returns earned on higher levels of nuclear and environmental cost recovery clause (ECRC) assets at PEF;
- favorable impact of interim and limited base rate relief at PEF;
- depreciation and amortization expense recognized in 2008 at PEC related to North Carolina Clean Smokestacks Act (Clean Smokestacks Act) amortization expense and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets; and
- favorable weather at the Utilities.

For the year ended December 31, 2008, our net income attributable to controlling interests was $830 million, or $3.17 per share, compared to $504 million, or $1.96 per share, for the same period in 2007. The increase in 2008 as compared to 2007 was due primarily to:

- favorable impact of discontinued non-utility businesses (Ongoing Earnings adjustment);
- favorable allowance for funds used during construction (AFUDC) at the Utilities;
- increased retail base rates at PEF;
- higher wholesale revenues at PEF;
- lower purchased power capacity costs at PEC due to the expiration of a power buyback agreement; and
- favorable net retail customer growth and usage at PEC.

Partially offsetting these items were:

- higher interest expense at PEF;
- higher income tax expense due to the benefit from the closure of certain federal tax years and positions in 2007;
- unfavorable net retail customer growth and usage at PEF;
- unfavorable weather at PEC;
- higher investment losses of certain employee benefit trusts at PEF and Corporate and Other resulting from the decline in market conditions; and
- higher depreciation and amortization expense at PEF excluding prior year recoverable storm amortization at PEF.

PROGRESS ENERGY CAROLINAS

PEC contributed net income available to parent totaling $513 million, $531 million and $498 million in 2009, 2008 and 2007, respectively. The decrease in net income available to parent for 2009 as compared to 2008 was primarily due to unfavorable net retail customer growth and usage, coal plant retirement charges, higher base depreciation and amortization expense and a cumulative prior period adjustment related to certain employee life insurance benefits, partially offset by Clean Smokestacks Act amortization and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets recognized in 2008 and the favorable impact of weather. PEC contributed Ongoing Earnings of $540 million in 2009. There were no Ongoing Earnings adjustments in 2008 and 2007. The 2009 Ongoing Earnings adjustments to net income available to parent were due to PEC recording a $17 million charge, net of tax, for the impact of PEC's decision to retire certain coal-fired generating units prior to the end of their estimated useful lives and recording a $10 million charge, net of tax, for a cumulative prior period adjustment related to certain employee life insurance benefits. Management does not consider these charges to be representative of PEC's fundamental core earnings and excluded these charges in computing PEC's Ongoing Earnings.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to lower purchased power capacity costs due to the expiration of a power buyback agreement, favorable AFUDC and favorable net retail customer growth and usage, partially offset by the unfavorable impact of weather and lower excess generation revenues.

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. “Base Revenues" is a non-GAAP measure and is defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues. We and PEC consider Base Revenues a useful measure to evaluate PEC's electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power expenses and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. Clause recoverable regulatory returns include the return on asset component of DSM, energy-efficiency and renewable energy clause revenues. We and PEC have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

REVENUES

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by year and by customer class, follows:

(in millions) Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**$ 1,179**	1.6	$ 1,160	(1.0)	$ 1,172
Commercial	**741**	(0.9)	748	0.4	745
Industrial	**374**	(10.1)	416	2.0	408
Governmental	**62**	(3.1)	64	4.9	61
Unbilled	**5**	–	8	–	(1)
Total retail base revenues	**2,361**	(1.5)	2,396	0.5	2,385
Wholesale base revenues	**310**	–	310	(12.7)	355
Total Base Revenues	**2,671**	(1.3)	2,706	(1.2)	2,740
Clause recoverable regulatory returns	**6**	–	–	–	–
Miscellaneous	**114**	11.8	102	5.2	97
Fuel and other pass-through revenues	**1,836**	–	1,621	–	1,548
Total operating revenues	**$ 4,627**	4.5	$ 4,429	1.0	$ 4,385

PEC's total retail base revenues were $2.361 billion and $2.396 billion for 2009 and 2008, respectively. The $35 million decrease in revenues was due primarily to the $58 million unfavorable impact of net retail customer growth and usage, partially offset by the $23 million favorable impact of weather. The unfavorable impact of net retail customer growth and usage was driven by a decrease in the average usage per retail customer, partially offset by a net 14,000 increase in the average number of customers for 2009 compared to 2008. However, PEC's rate of residential growth has declined as PEC's average number of customers increased a net 24,000 customers for 2008 compared to 2007. The favorable impact of weather was driven by higher heating and cooling degree days than 2008 of 3 percent and 5 percent, respectively. Additionally, cooling degree days were 6 percent higher than normal in 2009.

PEC's miscellaneous revenues increased $12 million in 2009 primarily due to higher transmission revenues.

PEC's total retail base revenues were $2.396 billion and $2.385 billion for 2008 and 2007, respectively. The $11 million increase in revenues was due primarily to the $34 million favorable impact of net retail customer growth and usage, partially offset by the $28 million unfavorable impact of weather. The favorable net retail customer growth and usage was driven by a net 24,000 increase in the average number of customers for 2008 compared to 2007, partially offset by lower average usage per retail customer. Weather had an unfavorable impact as cooling degree days were 12 percent lower than 2007, even though cooling degree days were comparable to normal.

PEC's wholesale base revenues were $310 million and $355 million for 2008 and 2007, respectively. The $45 million lower wholesale base revenues were driven by $24 million lower excess generation sales due to unfavorable market dynamics due to higher relative fuel costs and $22 million lower revenues related to capacity contracts with two major customers.

PEC's electric energy sales in kilowatt-hours (kWh) and the percentage change by year and by customer class were as follows:

(in millions of kWh) Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**17,117**	0.7	17,000	(1.2)	17,200
Commercial	**13,639**	(2.2)	13,941	(0.6)	14,032
Industrial	**10,368**	(9.0)	11,388	(4.3)	11,901
Governmental	**1,497**	2.1	1,466	1.9	1,438
Unbilled	**360**	–	(8)	–	(55)
Total retail kWh sales	**42,981**	(1.8)	43,787	(1.6)	44,516
Wholesale	**13,966**	(2.5)	14,329	(6.4)	15,309
Total kWh sales	**56,947**	(2.0)	58,116	(2.9)	59,825

The decrease in retail kWh sales in 2009 was primarily due to a decrease in average usage per retail customer. PEC's industrial kWh sales have decreased 9.0 percent from 2008, primarily due to continued reductions in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation as well as a continued downturn in the lumber and building materials segment as a result of declines in construction. Many of the manufacturers in PEC's service territory have been adversely impacted by the economic conditions, and we expect a relatively slow recovery in industrial sales once the economy begins to recover.

Wholesale kWh sales decreased for 2009 primarily due to decreased excess generation sales resulting from unfavorable market dynamics.

Industrial electric energy sales decreased in 2008 compared to 2007, primarily due to downturns in textile manufacturing and lumber and building materials segment as previously discussed.

PEC has experienced a decline in its retail and wholesale kWh sales due to the economic conditions in the United States. We cannot predict how long these conditions may last or the extent to which they may impact revenues. In the future, PEC's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation, as well as energy purchased in the market to meet customer load. Fuel and applicable portions of purchased power expenses are recovered primarily through cost-recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection from or refund to customers.

Fuel and purchased power expenses were $1.909 billion for 2009, which represents a $217 million increase compared to 2008. Fuel used in electric generation increased $334 million to $1.680 billion primarily due to $248 million higher deferred fuel expense and the $86 million net impact of higher fuel costs. The increase in deferred fuel expense was primarily due to the implementation of new fuel rates in North Carolina. The higher fuel costs were primarily due to higher coal prices. Purchased power expense decreased $117 million to $229 million compared to prior year. The decrease was primarily due to lower market purchases of $85 million and lower co-generation of $43 million primarily due to lower system requirements. See "PEC – Fuel and Purchased Power" in Item 1, "Business," for a summary of average fuel costs.

Fuel and purchased power expenses were $1.692 billion for 2008, which represents a $9 million increase compared to 2007. Purchased power expense increased $44 million to $346 million compared to 2007. The increase was primarily due to increased economical purchases in 2008 of $78 million, partially offset by the $38 million impact from the expiration of a power buyback agreement with North Carolina Eastern Municipal Power Agency (Power Agency). Fuel used in electric generation decreased $35 million to $1.346 billion primarily due to a $116 million decrease in deferred fuel expense, partially offset by increased fuel costs of $81 million. The decrease in deferred fuel expense was primarily driven by a $64 million impact from the implementation of state legislation that expanded the definition of the traditional fuel clause to include costs of commodities such as ammonia and limestone used in emissions control technologies (reagents), transmission charges and non-capacity-related costs of purchases and a $49 million impact related to under-recovered fuel costs. Deferred fuel expense was higher in 2007 primarily due to the collection of fuel costs from customers that had been previously under-recovered. The increase in fuel costs of $81 million was primarily due to an increase in coal prices, partially offset by the impacts of lower system requirements and a change in the generation mix.

Operation and Maintenance

O&M expense was $1.072 billion for 2009, which represents a $42 million increase compared to 2008. This increase was primarily due to coal plant retirement charges of $28 million, higher pension and benefit costs of $12 million and storm costs of $9 million, partially offset by lower emission allowance expense of $13 million resulting from lower system requirements, changes in generation mix and sales of nitrogen oxide (NOx) allowances. PEC recognized coal plant retirement charges ($17 million, net of tax) for the impact of the decision to retire 11 coal-fired units prior to the end of their useful lives (See "Future Liquidity and Capital Resources – PEC Other Matters" and "Other Matters – Energy Demand"). Management determined that such charges should be an exclusion from PEC's Ongoing Earnings.

O&M expense was $1.030 billion for 2008, which represents a $6 million increase compared to 2007. This increase was driven primarily by a $33 million increase in nuclear expenses, of which $18 million relates to refurbishments, preventive maintenance and incremental outage expenses at Brunswick Nuclear Plant (Brunswick). Additionally, O&M increased due to a $7 million increase in estimated environmental remediation expenses (See Note 21A), partially offset by $19 million lower employee benefits and $16 million lower nuclear plant outage and maintenance costs. The decrease in employee benefits was primarily due to the 2007 impact from changes in stock-based compensation plans and higher relative employee incentive goal achievement. The decrease in nuclear plant outage and maintenance costs was primarily due to two nuclear refueling and maintenance outages in 2008 compared to three in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $470 million for 2009, which represents a $48 million decrease compared to 2008. This decrease was primarily attributable to the $52 million of depreciation associated with the accelerated cost-recovery program for nuclear generating assets recognized during 2008 (See Note 7B) and the $15 million of Clean Smokestacks Act amortization recognized in 2008, partially offset by the $21 million impact of depreciable asset base increases. The North Carolina jurisdictional aggregate minimum amount of accelerated cost recovery has been met, and the South Carolina jurisdictional obligation was terminated by the

Public Service Commission of South Carolina (SCPSC). PEC does not anticipate recording additional accelerated depreciation in the North Carolina jurisdiction, but will record depreciation over the remaining useful lives of the assets. In accordance with a regulatory order, PEC ceased to amortize Clean Smokestacks Act compliance costs, but will record depreciation over the useful lives of the assets (See Note 7B).

Depreciation, amortization and accretion expense was $518 million for 2008, which represents a $1 million decrease compared to 2007. This decrease was primarily attributable to $19 million lower Clean Smokestacks Act amortization, $8 million lower GridSouth Transco, LLC (GridSouth) amortization and $3 million lower storm deferral amortization, partially offset by $15 million higher depreciation associated with the accelerated cost-recovery program for nuclear generating assets and the $15 million impact of depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $210 million, $198 million and $192 million in 2009, 2008 and 2007, respectively. The $12 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts taxes due to higher operating revenues and higher property tax rates. Gross receipts taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Total Other Income, Net

Total other income, net was $20 million for 2009, which represents a $23 million decrease compared to 2008. This decrease was primarily due to a cumulative prior period adjustment related to certain employee life insurance benefits and lower interest income resulting from lower average eligible deferred fuel balances. During the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net by $16 million and decreased net income available to parent by $10 million. The prior period adjustment is not material to previously issued or current period financial statements. Management determined that the adjustment should be an exclusion from PEC’s Ongoing Earnings.

Total other income, net was $43 million for 2008, which represents a $6 million increase compared to 2007. This increase was primarily due to $17 million favorable AFUDC equity related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs, partially offset by $9 million lower interest income resulting from lower average eligible deferred fuel balances and lower temporary investment balances.

Total Interest Charges, Net

Total interest charges, net was $195 million for 2009, which represents a $12 million decrease compared to 2008. This decrease was primarily due to lower interest rates on variable rate debt, partially offset by higher interest as a result of higher average debt outstanding.

Total interest charges, net was $207 million for 2008, which represents a $3 million decrease compared to 2007. This decrease was primarily due to the $7 million favorable AFUDC debt related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs and the $4 million impact of a decrease in average long-term debt, offset by an $11 million interest benefit resulting from the resolution of tax matters in 2007.

Income Tax Expense

Income tax expense was $277 million, $298 million and $295 million in 2009, 2008 and 2007, respectively. The $21 million income tax expense decrease in 2009 compared to 2008 was primarily due to the impact of lower pre-tax income and the $5 million favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from nonqualified nuclear decommissioning trusts (NDTs) to qualified NDTs. The $3 million income tax expense increase in 2008 compared to 2007 was primarily due to the $14 million impact of higher pre-tax income and the $5 million impact related to the deduction for domestic production activities, partially offset by the $7 million tax impact of employee stock-based benefits and the $7 million impact of the increase in AFUDC equity previously discussed. AFUDC equity is excluded from the calculation of income tax expense.

PROGRESS ENERGY FLORIDA

PEF contributed net income available to parent and Ongoing Earnings totaling $460 million, $383 million and $315 million in 2009, 2008 and 2007, respectively. The increase in net income available to parent for 2009 as compared to 2008 was primarily due to the higher net impact of returns earned on higher levels of nuclear and ECRC assets to be recovered through respective cost-recovery clauses, the favorable impact of interim and limited base rate relief (See Note 7C) and the favorable impact of weather, partially offset by the unfavorable impact of retail customer growth and usage, higher base depreciation and amortization expense, and higher O&M.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to favorable AFUDC, increased retail base rates and higher wholesale revenues, partially offset by higher interest expense, unfavorable net retail customer growth and usage, higher depreciation and amortization expense excluding recoverable storm amortization, and higher investment losses of certain employee benefit trusts.

The revenue tables that follow present the total amount and percentage change of total operating revenues and its components. “Base Revenues” is a non-GAAP measure and is defined as operating revenues excluding clause recoverable regulatory returns, miscellaneous revenues and fuel and other pass-through revenues. We and PEF consider Base Revenues a useful measure to evaluate PEF’s electric operations because fuel and other pass-through revenues primarily represent the recovery of fuel, applicable portions of purchased power and other pass-through expenses through cost-recovery clauses and, therefore, do not have a material impact on earnings. Clause recoverable regulatory returns include the revenues associated with the return on asset component of nuclear cost-recovery and ECRC revenues. We and PEF have included the reconciliation and analysis that follows as a complement to the financial information we provide in accordance with GAAP.

REVENUES

A reconciliation of Base Revenues to GAAP operating revenues, including the percentage change by year and by customer class, follows:

(in millions) Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**$ 946**	5.9	$ 893	3.4	$ 864
Commercial	**340**	3.7	328	6.8	307
Industrial	**72**	(5.3)	76	5.6	72
Governmental	**87**	6.1	82	5.1	78
Unbilled	**9**	–	(1)	–	1
Total retail base revenues	**1,454**	5.5	1,378	4.2	1,322
Wholesale base revenues	**207**	5.1	197	33.1	148
Total Base Revenues	**1,661**	5.5	1,575	7.1	1,470
Clause recoverable regulatory returns	**87**	690.9	11	450.0	2
Miscellaneous	**189**	6.2	178	4.7	170
Fuel and other pass-through revenues	**3,314**	–	2,967	–	3,107
Total operating revenues	**$ 5,251**	11.0	$ 4,731	(0.4)	$ 4,749

PEF’s total retail base revenues were $1.454 billion and $1.378 billion for 2009 and 2008, respectively. The $76 million increase was primarily due to the $79 million favorable impact of interim and limited base rate relief and the $36 million favorable impact of weather, partially offset by the $41 million unfavorable impact of retail customer growth and usage. The interim and limited base rate relief was approved by the FPSC effective July 1, 2009, as discussed in Note 7C. Of the $79 million interim and limited base rate relief, $7 million related to interim rate relief, which was in effect for only 2009, and $72 million related to limited rate relief, which will continue in accordance with the base rate proceeding with an annual revenue requirement of $132 million. The favorable impact of weather was primarily driven by 14 percent higher heating degree days than 2008 and 6 percent higher cooling degree days than 2008. Heating degree days were 4 percent lower than normal in 2009 and 16 percent lower than normal in

2008. In addition to lower average usage per customer, PEF's average number of customers for 2009, compared to 2008, decreased a net 8,000 customers and had no change in customers for 2008, compared to 2007.

PEF's clause recoverable regulatory returns were $87 million and $11 million for 2009 and 2008, respectively. The $76 million higher revenues related to nuclear cost recovery and ECRC assets of $61 million and $15 million, respectively. As a result of an FPSC regulatory order effective in January 2009, PEF is allowed to earn returns on certain costs related to nuclear construction, as discussed in Note 7C. We anticipate higher returns on ECRC assets in 2010 due to placing approximately $790 million of Clean Air Interstate Rule (CAIR) projects into service in late 2009. However, we do not anticipate a significant change in returns on nuclear cost-recovery assets in 2010 related to Levy.

PEF's total retail base revenues were $1.378 billion and $1.322 billion for 2008 and 2007, respectively. The $56 million increase was primarily due to $90 million of base rate increases, partially offset by the $32 million impact of unfavorable net retail customer growth and usage. The increase in base rates was due to $53 million from Hines 4 being placed in service and the $37 million transfer of Hines 2 cost recovery from the fuel clause to base rates. These base rate changes occurred in accordance with PEF's 2005 base rate settlement agreement.

PEF's wholesale base revenues of $197 million and $148 million for 2008 and 2007, respectively, increased $49 million. The increase was primarily due to several new and amended contracts.

PEF's electric energy sales and the percentage change by year and by customer class were as follows:

(in millions of kWh) Customer Class	**2009**	% Change	2008	% Change	2007
Residential	**19,399**	0.4	19,328	(2.9)	19,912
Commercial	**11,884**	(2.1)	12,139	(0.4)	12,183
Industrial	**3,285**	(13.2)	3,786	(0.9)	3,820
Governmental	**3,256**	(1.4)	3,302	(1.9)	3,367
Unbilled	**131**	–	(99)	–	(6)
Total retail kWh sales	**37,955**	(1.3)	38,456	(2.1)	39,276
Wholesale	**3,835**	(43.1)	6,734	11.8	6,024
Total kWh sales	**41,790**	(7.5)	45,190	(0.2)	45,300

Wholesale base revenues increased in 2009, despite decreased wholesale kWh sales in 2009, primarily due to committed capacity revenues. The wholesale kWh sales decreased primarily due to market conditions in which wholesale customers fulfilled a portion of their system requirements from other sources. Many of the new and amended capacity contracts entered into in 2008 expired by the end of 2009. Given the current economic conditions discussed below, PEF does not believe it is likely to replace these wholesale contracts in 2010.

Retail base revenues increased in 2009, despite a decrease in kWh sales for the same period, primarily due to the impact of interim and limited base rate relief approved by the FPSC in 2009 (See Note 7C). Retail base revenues increased in 2008, despite a decrease in kWh sales for the same period, primarily due to an increase in base rates in accordance with PEF's 2005 base rate settlement agreement, as previously discussed.

The economic conditions and general housing downturn in the United States has continued to contribute to a slowdown in customer growth and usage in PEF's service territory resulting in a 1.3 percent decrease in retail kWh sales for 2009, compared to 2008, and a 2.1 percent decrease for 2008, compared to 2007. The impact of the general housing downturn was especially severe in several states, including Florida. Additionally, we believe the current economic conditions have impacted our wholesale customers' usage. We cannot predict how long these economic conditions may last or the extent to which revenues may be impacted. In the future, PEF's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation, as well as energy purchased in the market to meet customer load. Fuel and purchased power expenses are recovered primarily through cost-recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection from or refund to customers.

Fuel and purchased power expenses were $2.754 billion in 2009, which represents a $126 million increase compared to 2008. Fuel used in electric generation increased $397 million to $2.072 billion compared to 2008. This increase was primarily due to higher deferred fuel expense of $467 million driven by the implementation of new fuel rates, partially offset by decreased current year fuel costs of $70 million. The decrease in current year fuel costs was primarily due to lower system requirements. Purchased power expense decreased $271 million compared to the same period in 2008, primarily due to $164 million lower interchange costs and a decrease in the recovery of deferred capacity costs of $91 million, both resulting from lower system requirements. See "PEF – Fuel and Purchased Power" in Item 1, "Business," for a summary of average fuel costs.

Fuel and purchased power expenses were $2.628 billion in 2008, which represents an $18 million decrease compared to 2007. Fuel used in electric generation decreased $89 million to $1.675 billion primarily due to a $381 million decrease in deferred fuel expense, partially offset by increased fuel costs of $293 million. The decrease in deferred fuel expense was primarily due to the regulatory approval to lower the fuel factor for customers effective January 2008 as a result of over-recovery of fuel costs in the prior year. With the increase in fuel prices experienced in 2008, PEF successfully sought a mid-course fuel correction, but the revised fuel factors were not effective until August 2008. The increase in fuel costs was primarily due to increased fuel prices and a change in generation mix. Purchased power expense increased $71 million to $953 million compared to 2007. This increase was primarily due to increased purchases of $37 million as a result of higher fuel costs and an increase in the recovery of deferred capacity costs of $34 million.

Operation and Maintenance

O&M expense was $839 million in 2009, which represents a $26 million increase compared to 2008. The increase was primarily due to $63 million higher ECRC and energy conservation cost recovery clause (ECCR) costs primarily due to an increase in current year rates for recovery of emission allowances, higher pension costs of $24 million and higher nuclear plant outage and maintenance costs of $14 million, partially offset by lower storm cost recovery of $66 million due to the surcharge that ended in July 2008 and the impact of a change in our earned vacation policy of $11 million. The ECRC and ECCR expenses and replenishment of storm damage reserve are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. Pension costs are higher due to a $20 million pension credit in the prior year. Substantially all of 2009's pension expense has been deferred in accordance with an FPSC order (See Note 7C). In the aggregate, O&M expenses recoverable through base rates increased $25 million compared to the same period in 2008.

O&M expense was $813 million in 2008, which represents a $21 million decrease compared to 2007. The decrease was primarily due to $24 million lower ECRC costs due to a decrease in the rates resulting from over-recovery, $12 million lower employee benefit costs primarily due to the 2007 impact from changes in stock-based compensation plans and $12 million lower sales and use tax audit adjustment, partially offset by $19 million related to storm damage reserves replenishment surcharge in effect August 2007 through July 2008 in accordance with a regulatory order, and $11 million higher plant outage and maintenance costs. The ECRC and replenishment of storm damage reserves expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In the aggregate, O&M expenses recoverable through base rates decreased $19 million compared to the same period in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $502 million for 2009, which represented an increase of $196 million compared to 2008, primarily due to higher nuclear cost-recovery amortization of $155 million (See Note

7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $31 million compared to 2008, primarily due to depreciable asset base increases.

Depreciation, amortization and accretion expense was $306 million for 2008, which represented a decrease of $60 million compared to 2007, primarily due to $75 million lower amortization of unrecovered storm restoration costs and a $7 million write-off in 2007 of leasehold improvements primarily related to vacated office space, partially offset by the $20 million impact of depreciable asset base increases. Storm restoration costs, which were fully amortized in August 2007, were recovered through a storm-recovery surcharge and, therefore, had no material impact on earnings (See Note 7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $13 million compared to 2007, primarily due to depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $347 million, $309 million and $309 million in 2009, 2008 and 2007, respectively. The $38 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts and franchise taxes due to higher operating revenues. Gross receipts and franchise taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expense was an expense of $7 million in 2009, income of $5 million in 2008 and an expense of $8 million in 2007. The $7 million expense in 2009 and the $8 million expense in 2007 were primarily due to regulatory disallowances of fuel costs (See Note 7C). The $5 million income in 2008 was primarily due to gain on land sales.

Total Other Income, Net

Total other income, net was $100 million for 2009, which represents a $6 million increase compared to 2008. This increase was primarily due to the $16 million of investment gains on certain employee benefit trusts resulting from improved market conditions, partially offset by $5 million lower interest income resulting from lower short-term investment balances and $4 million unfavorable AFUDC equity related to eligible construction project costs, primarily due to placing the repowered Bartow Plant into service in 2009.

Total other income, net was $94 million for 2008, which represents a $46 million increase compared to 2007. This increase was primarily due to $54 million favorable AFUDC equity related to eligible construction project costs, partially offset by $11 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

Total Interest Charges, Net

Total interest charges, net was $231 million in 2009, which represents an increase of $23 million compared to 2008. The increase in interest charges was primarily due to higher interest as a result of higher average debt outstanding.

Total interest charges, net was $208 million in 2008, which represents an increase of $35 million compared to 2007. The increase in interest charges was primarily due to the $60 million impact of an increase in average long-term debt, partially offset by $16 million favorable AFUDC debt related to costs associated with eligible construction projects and $7 million interest benefit resulting from the resolution of tax matters in 2008.

Income Tax Expense

Income tax expense was $209 million, $181 million and $144 million in 2009, 2008 and 2007, respectively. The $28 million income tax expense increase in 2009 compared to 2008 was primarily due to the $40 million impact of higher pre-tax income compared to the prior year, partially offset by the $11 million impact of the favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from the nonqualified NDT fund to the qualified NDT fund. The $37 million income tax expense increase in 2008 compared to 2007 was primarily due to the $40 million impact of higher pre-tax income compared to 2007, $6 million benefit related to the closure of certain federal tax years and positions in 2007, $4 million due to the accelerated amortization of tax-related regulatory assets in accordance with PEF's 2005 base rate settlement agreement, and $3 million related to the deduction for domestic production activities, partially offset by the $21 million impact of favorable AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense.

CORPORATE AND OTHER

The Corporate and Other segment primarily includes the operations of the Parent, PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative disclosure requirements as a reportable business segment. A discussion of the items excluded from Corporate and Other's Ongoing Earnings is included in the detailed discussion and analysis below. Management believes the excluded items are not representative of our fundamental core earnings. The following table reconciles Corporate and Other's Ongoing Earnings to GAAP net income attributable to controlling interests:

(in millions)	**2009**	Change	2008	Change	2007
Other interest expense	**$ (253)**	$ (30)	$ (223)	$ (18)	$ (205)
Other income tax benefit	**87**	1	86	(19)	105
Other income (expense)	**12**	13	(1)	17	(18)
Ongoing Earnings	**(154)**	(16)	(138)	(20)	(118)
CVO mark-to-market	**19**	19	–	2	(2)
Valuation allowance and related net operating loss carry forward	**–**	3	(3)	(3)	–
Impairment [(a)]	**(2)**	(2)	–	–	–
Discontinued operations attributable to controlling interests, net of tax	**(79)**	(136)	57	246	(189)
Net loss attributable to controlling interests	**(216)**	(132)	(84)	225	(309)

[(a)] Calculated using assumed tax rate of 40 percent.

Other Interest Expense

Other interest expense was $253 million, $223 million and $205 million for 2009, 2008 and 2007, respectively. The $30 million increase for 2009 compared to 2008 was primarily due to higher average debt outstanding at the Parent. The $18 million increase for 2008 compared to 2007 was primarily due to a $6 million 2007 benefit related to the closure of certain federal tax years and positions and a decrease in the interest allocated to discontinued operations. The decrease in interest allocated to discontinued operations resulted from the allocations of interest expense in early 2007 to operations that were sold later in 2007. An immaterial amount and $13 million of interest expense were allocated to discontinued operations for 2008 and 2007, respectively. No interest expense was allocated to discontinued operations in 2009.

Other Income Tax Benefit

Other income tax benefit was $87 million, $86 million and $105 million for 2009, 2008 and 2007, respectively. The $1 million increase for 2009 compared to 2008 was primarily due to higher pre-tax expenses, partially offset by the unfavorable impact at the Corporate level resulting from the deductions taken by the Utilities related to NDT funds (See "Progress Energy Carolinas − Income Tax Expense" and "Progress Energy Florida − Income Tax Expense"). The $19 million decrease for 2008 compared to 2007 was primarily due to the 2007 benefit related to the closure of certain federal tax years and positions.

Other Income (Expense)

Other income (expense) was $12 million income, $1 million expense and $18 million expense for 2009, 2008 and 2007, respectively. The $13 million change for 2009 compared to 2008 was primarily due to investment gains on certain employee benefit trusts resulting from improved financial market conditions. The $17 million change for 2008 compared to 2007 was primarily due to $15 million decreased indirect corporate overhead due to divestitures completed in 2007 and $12 million decreased legal expenses, partially offset by $8 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

CVO Mark-to-Market

Progress Energy issued 98.6 million CVOs in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments are based on the net after-tax cash flows the facilities generate (See Note 15). The CVOs had a fair value of $15 million at December 31, 2009, and $34 million at December 31, 2008 and 2007. Progress Energy recorded unrealized gains of $19 million for 2009 and unrealized losses of $2 million for 2007, to record the changes in fair value of the CVOs, which had average unit prices of $0.16 at December 31, 2009 and $0.35 at December 31, 2008 and 2007.

Valuation Allowance and Related Net Operating Loss Carry Forward

We previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of Progress Energy Ventures, Inc.'s (PVI) nonregulated generation facilities and energy marketing and trading operations. In 2008, we recorded an additional $6 million deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. We also evaluated the total state net operating loss carry forward and recorded a partial valuation allowance of $9 million, which more than offset the change in estimate.

Impairment

In 2009, Progress Energy recorded impairments of certain investments of our Affordable Housing portfolio.

Discontinued Operations Attributable to Controlling Interests, Net of Tax

We completed our business strategy of divesting of nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. See Note 3 for additional information related to discontinued operations.

In 2009, we recognized $79 million of expense from discontinued operations attributable to controlling interests, net of tax, which was primarily due to a jury delivering a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates previously engaged in coal-based solid synthetic fuels operations. As a result, we recorded an after-tax charge of $74 million to discontinued operations in 2009, which was net of a previously recorded indemnification liability. The ultimate resolution of these matters could result in further adjustments. See Note 22D for additional information.

During 2008 we recognized $57 million of income from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $49 million after-tax gains on sales of our coal terminals and docks in West Virginia and Kentucky (Terminals) and our remaining coal mining businesses.

In 2007, we recognized $189 million of expense from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $283 million net losses related to the exit of the Competitive Commercial Operations (CCO) business, partially offset by $83 million net earnings related to the Terminals and Synthetic Fuels businesses. The net losses from the CCO business were primarily due to the $349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to de-designated natural gas hedges. We had substantial operations associated with the production of coal-based solid synthetic fuels. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We prepared our Consolidated Financial Statements in accordance with GAAP. In doing so, we made certain estimates that were critical in nature to the results of operations. The following discusses those significant accounting policies and estimates that may have a material impact on our financial results and are subject to the greatest amount of subjectivity. We have discussed the development and selection of these critical accounting policies and estimates with the Audit and Corporate Performance Committee (Audit Committee) of our board of directors.

IMPACT OF UTILITY REGULATION

Our regulated utilities segments are subject to regulation that sets the prices (rates) we are permitted to charge customers based on the costs that regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by a nonregulated company. The application of GAAP for regulated operations to this ratemaking process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the different ratemaking processes in each state in which we operate, a significant amount of regulatory assets has been recorded. We continually review these regulatory assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. Additionally, the state regulatory agencies' ratemaking processes often provide flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets.

Our conclusion that we and the Utilities meet the criteria to apply GAAP for regulated operations is a material assumption in the presentation and evaluation of our and the Utilities' financial position and results of operations. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by actions of our regulators, competitive forces and restructuring in the electric utility industry. State regulators may not allow the Utilities to increase future retail rates required to recover their operating costs or provide an adequate return on investment, or in the manner requested. State regulators may also seek to reduce or freeze retail rates. Such events occurring over a sustained period could result in the Utilities no longer meeting the criteria for the continued application of GAAP for regulated operations. In the event that GAAP for regulated operations no longer applies to one or both of the Utilities, we are subject to the risk that regulatory assets and liabilities would be eliminated and utility plant assets may be impaired, unless an appropriate recovery mechanism was provided. Additionally, our financial condition, cash flows and results of operations may be adversely impacted. See Note 7 for additional information related to the impact of utility regulation on our operations.

We evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. If an impairment indicator exists, the asset group held and used is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred. The carrying values of our total utility plant, net at December 31 were as follows:

(in millions)		**2009**		2008
Progress Energy	**$**	**19,733**	$	18,293
PEC		**9,886**		9,385
PEF		**9,733**		8,790

As discussed in Note 13, our financial assets and liabilities are primarily comprised of derivative financial instruments and marketable debt and equity securities held in our nuclear decommissioning trusts. Substantially all unrealized gains and losses on derivatives and all unrealized gains and losses on nuclear decommissioning trust investments are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Therefore, the impact of fair value measurements from recurring financial assets and liabilities on our or the Utilities' earnings is not significant.

ASSET RETIREMENT OBLIGATIONS

Asset Retirement Obligations (AROs) represent legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability.

AROs have no impact on the income of the Utilities as the effects are offset by the establishment of regulatory assets and regulatory liabilities.

Progress Energy's, PEC's and PEF's total AROs at December 31, 2009, were $1.170 billion, $801 million, and $369 million, respectively. We calculated the present value of our AROs based on estimates which are dependent on su bjective factors such as management's estimated retirement costs, the timing of future cash flows and the selection of appropriate discount and cost escalation rates. These underlying assumptions and estimates are made as of a point in time and are subject to change. These changes could materially affect the AROs, although changes in such estimates should not affect earnings, because these costs are expected to be recovered through rates.

Nuclear decommissioning AROs represent 95 percent, 97 percent, and 91 percent, respectively, of Progress Energy's, PEC's and PEF's total AROs at December 31, 2009. To determine nuclear decommissioning AROs, we utilize periodic site-specific cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. Our regulators require updated cost estimates for nuclear decommissioning every five years. These cost studies are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. Changes in PEC's and PEF's nuclear decommissioning site-specific cost estimates or the use of alternative cost escalation or discount rates could be material to the nuclear decommissioning liabilities recognized.

PEC obtained updated cost studies for its nuclear plants in 2009, using 2009 cost factors. If the site-specific cost estimates increased by 10 percent, PEC's AROs would have increased by $77 million. If the inflation adjustment increased 25 basis points, PEC's AROs would have increased by $169 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEC's AROs by $56 million.

PEF obtained an updated cost study for its nuclear plant in 2008, using 2008 cost factors. If the site-specific cost estimates increased by 10 percent, PEF's AROs would have increased by $32 million. If the inflation adjustment increased 25 basis points, PEF's AROs would have increased by $25 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEF's AROs by $23 million.

GOODWILL

As discussed in Note 8, goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. The carrying amounts of goodwill at December 31, 2009 and 2008, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. We perform our annual impairment tests as of April 1 each year. During the second quarter of 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired. If the fair value of PEC had been lower by 10 percent and the fair value of PEF had been lower by 7.5 percent, there still would be no impact on the reported value of their goodwill.

We calculate the fair value of our utility segments by considering various factors, including valuation studies based primarily on income and market approaches. More emphasis is applied to the income approach as substantially all of the utility segments' cash flows are from rate-regulated operations. In such environments, revenue requirements are adjusted periodically by regulators based on factors including levels of costs, sales volumes and costs of capital. Accordingly, the utility segments operate to some degree with a buffer from the direct effects, positive or negative, of significant swings in market or economic conditions.

The income approach uses discounted cash flow analyses to determine the fair value of the utility segments. The estimated future cash flows from operations are based on the utility segments' business plans, which reflect management's assumptions related to customer usage based on internal data and economic data obtained from third-party sources. The business plans assume the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, the timing of anticipated significant future capital investments, the anticipated earnings and returns related to such capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also determines the appropriate discount rate for the utility segments based on the weighted average cost of capital for each utility, which takes into account both the cost of equity and pre-tax cost of debt. As each utility segment has a different risk profile based on the nature of its operations, the discount rate for each reporting unit may differ.

The market approach uses implied market multiples derived from comparable peer utilities and market transactions to estimate the fair value of the utility segments. Peer utilities are evaluated based on percentage of revenues generated by regulated utility operations; percentage of revenues generated by electric operations; generation mix, including coal, gas, nuclear and other resources; market capitalization as of the valuation date; and geographic location. Comparable market transactions are evaluated based on the availability of financial transaction data and the nature and geographic location of the businesses or assets acquired, including whether the target company had a significant electric component. The selection of comparable peer utilities and market transactions, as well as the appropriate multiples from within a reasonable range, is a matter of professional judgment.

The calculations in both the income and market approaches are highly dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates from a marketplace participant's perspective, and the selection of peer utilities and marketplace transactions for comparative valuation purposes. These underlying assumptions and estimates are made as of a point in time. If these assumptions change or should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, the fair value of the utility segments could be significantly different in future periods, which could result in a future impairment charge to goodwill.

As an overall test of the reasonableness of the estimated fair values of the utility segments, we compared their combined fair value estimate to Progress Energy's market capitalization as of April 1, 2009. The analysis confirmed that the fair values were reasonably representative of market views when applying a reasonable control premium to the market capitalization.

We monitor for events or circumstances, including financial market conditions and economic factors, that may indicate an interim goodwill impairment test is necessary. We would perform an interim impairment test should any events occur or circumstances change that would more likely than not reduce the fair value of a utility segment below its carrying value.

UNBILLED REVENUE

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues included unbilled electric utilities base revenues earned when service has been delivered but not billed by the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis through the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for the electric utility revenues associated with unbilled sales is recognized. Unbilled revenues are estimated by applying a weighted average revenue/kWh for all customer classes to the number of estimated kWh delivered but not billed. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses.

Amounts recorded as receivables on the Balance Sheets at December 31 related to unbilled revenues were as follows:

(in millions)	2009	2008
Progress Energy	**$ 193**	$ 182
PEC	**125**	120
PEF	**68**	62

INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. As discussed in Note 14, deferred income tax assets and liabilities represent the future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax- planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. In accordance with GAAP, the uncertainty and judgment involved in the determination and filing of income taxes is accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. A two-step process is required: recognition of the tax benefit based on a “more-likely-than-not” threshold, and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority.

PENSION COSTS

As discussed in Note 16A, we maintain qualified noncontributory defined benefit retirement (pension) plans. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. Our reported costs are dependent on numerous factors resulting from actual plan experience and assumptions of future experience. For example, such costs are impacted by employee demographics, changes made to plan provisions, actual plan asset returns and key actuarial assumptions, such as expected long-term rates of return on plan assets and discount rates used in determining benefit obligations and annual costs.

Due to a slight decrease in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate to calculate the present value of future benefit payments, we decreased the discount rate to 6.00% at December 31, 2009, from 6.30% at December 31, 2008, which will increase 2010 pension costs, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study, which matches our projected benefit payments to a high-quality corporate yield curve. Consistent with general market conditions, our plan assets performed well in 2009 with returns of approximately 23%. That positive asset performance will result in decreased pension costs in 2010, all other factors remaining constant. In addition, contributions to pension plan assets in late 2009 and 2010 will result in decreased pension costs in 2010 due to increased asset balances, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2010 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2010 will be $80 million to $90 million, compared with $107 million (before the $34 million deferral; see Notes 7C and 16A) recognized in 2009.

We have pension plan assets with a fair value of approximately $1.7 billion at December 31, 2009. Our expected rate of return on pension plan assets is 8.75%. The expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2009, we lowered the expected rate of return from the previously used 9.00%, due primarily to the uncertainties resulting from the severe capital market deterioration in 2008. A 25 basis point change in the expected rate of return for 2009 would have changed 2009 pension costs by approximately $4 million.

Another factor affecting our pension costs, and sensitivity of the costs to plan asset performance, is the method selected to determine the market-related value of assets, i.e., the asset value to which the 8.75% expected long-term rate of return is applied. Entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. We have historically used a five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. Changes in plan asset performance are reflected in pension costs sooner under the fair value method than the five-year averaging method, and, therefore, pension costs tend to be more volatile using the fair value method. Approximately 50 percent of our pension plan assets are subject to each of the two methods.

Since PEC and PEF participate in our pension plans, the general discussion above applies to PEC and PEF. PEC and PEF have not completed evaluating their 2010 pension costs. PEC estimates that the total cost recognized for pensions in 2010 will be $25 million to $30 million, compared with $32 million recognized in 2009. A 25 basis point change in the expected rate of return for 2009 would have changed PEC's 2009 pension costs by approximately $2 million. PEF estimates that the total cost recognized for pensions in 2010 will be $40 million to $45 million, compared with $57 million (before $34 million deferral; see Note 16A) recognized in 2009. A 25 basis point change in the expected rate of return for 2009 would have changed PEF's 2009 pension costs by approximately $2 million .

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

Our significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations, including expenditures for environmental compliance. We rely upon our operating cash flow, substantially all of which is generated by the Utilities, commercial paper and bank facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity. As discussed in "Future Liquidity and Capital Resources" below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized.

The majority of our operating costs are related to the Utilities. Most of these costs are recovered from ratepayers in accordance with various rate plans. We are allowed to recover certain fuel, purchased power and other costs incurred by PEC and PEF through their respective recovery clauses. The types of costs recovered through clauses vary by jurisdiction. Fuel price volatility can lead to over- or under-recovery of fuel costs, as changes in fuel prices are not immediately reflected in fuel surcharges due to regulatory lag in setting the surcharges. As a result, fuel price volatility can be both a source of and a use of liquidity resources, depending on what phase of the cycle of price volatility we are experiencing. Changes in the Utilities' fuel and purchased power costs may affect the timing of cash flows, but not materially affect net income.

As a registered holding company, our establishment of intercompany extensions of credit is subject to regulation by the Federal Energy Regulatory Commission (FERC). Our subsidiaries participate in internal money pools, administered by PESC, to more effectively utilize cash resources and reduce external short-term borrowings. The utility money pool allows the Utilities to lend to and borrow from each other. A non-utility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and non-utility money pools but cannot borrow funds.

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's $4.3 billion of senior unsecured debt and potentially funding the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. In recent years, rather than paying dividends to the Parent, the Utilities, to a large extent, have retained their free cash flow to fund their capital expenditures. During 2009, PEC paid a dividend of $200 million to the Parent and PEF received equity contributions of $620 million from the Parent. PEC and PEF expect to pay dividends to the Parent in 2010. There are a number of factors that impact the Utilities' decision or ability to pay dividends to the Parent or to seek equity contributions from the Parent, including capital expenditure decisions and the timing of recovery of fuel and other pass-through costs. Therefore, we cannot predict the level of dividends or equity contributions between the Utilities and the Parent from year to year. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Cash from operations, commercial paper issuance, borrowings under our credit facilities, long-term debt financings, and/or limited ongoing sales of common stock from our Progress Energy Investor Plus Plan (IPP), employee benefit and stock option plans are expected to fund capital expenditures, long-term debt maturities and common stock dividends for 2010. For the fiscal year 2010, we plan, subject to market conditions, to realize up to $500 million from the sale of stock through ongoing equity sales. As discussed further in "Credit Rating Matters," and in Item 1A, "Risk Factors," our ability to access the capital markets on favorable terms may be negatively impacted by recent, and potentially future, rating actions.

We have 16 financial institutions that support our combined $2.030 billion revolving credit facilities for the Parent, PEC and PEF, thereby limiting our dependence on any one institution. The credit facilities serve as back-ups to our commercial paper programs. To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009, the Parent had no outstanding borrowings under its credit facility, an outstanding commercial paper balance of $140 million and had issued $37 million of letters of credit, which were supported by the revolving credit facility. At December 31, 2009, PEC and PEF had no outstanding commercial paper. Based on these outstanding amounts at December 31, 2009, there was

$1.853 billion available for additional borrowings. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

Borrowings under our revolving credit agreement (RCA) during 2008, which were repaid during 2009, coupled with commercial paper, long-term debt and equity issuances in 2009, provided liquidity during a period of uncertain financial market conditions. We will continue to monitor the credit markets to maintain an appropriate level of liquidity.

At December 31, 2009, PEC and PEF had limited counterparty mark-to-market exposure for financial commodity hedges (primarily gas and oil hedges) due to spreading our concentration risk over a number of counterparties. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 17A for additional information with regard to our commodity derivatives.

At December 31, 2009, we had limited mark-to-market exposure to certain financial institutions under pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions for each of the Parent, PEC and PEF. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, the sum of the Parent's, PEC's and PEF's open pay-fixed forward starting swaps was each in a net mark-to-market asset position. See Note 17B for additional information with regard to our interest rate derivatives.

Our pension trust funds and nuclear decommissioning trust funds are managed by a number of financial institutions, and the assets being managed are diversified in order to limit concentration risk in any one institution or business sector.

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. Risk factors associated with credit facilities and credit ratings are discussed below and in Item 1A, "Risk Factors."

The following discussion of our liquidity and capital resources is on a consolidated basis.

HISTORICAL FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

CASH FLOWS FROM OPERATIONS

Net cash provided by operations is the primary source used to meet operating requirements and a portion of capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2009, 2008 and 2007. Net cash provided by operating activities for the three years ended December 31, 2009, 2008 and 2007, was $2.271 billion, $1.218 billion and $1.252 billion, respectively.

Net cash provided by operating activities for 2009 increased when compared with 2008. The $1.053 billion increase in operating cash flow was primarily due to a $623 million increase in the recovery of deferred fuel costs due to higher fuel rates and $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $200 million net refunds of cash collateral in 2009. These impacts were partially offset by $221 million of pension and other benefits contributions made in 2009.

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $34 million decrease in operating cash flow was primarily due to a $450 million decrease in the recovery of fuel costs due to the 2008 under-recovery driven by rising fuel costs, compared to an over-recovery of fuel costs during the corresponding period in 2007; $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $55 million in net refunds of cash collateral in 2007, primarily at PEF; and a $226 million increase in inventory purchases, primarily coal, driven by higher prices. These impacts were partially offset by a $419 million increase from accounts receivable, primarily related to our divested CCO operations and former synthetic fuels businesses; the $347 million payment made in 2007 to exit the contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO (the Georgia contracts) (See Note 3C); a $117 million increase from accounts payable; and a $106 million increase from income taxes, net. The increase from accounts receivable was primarily driven by the settlement of $234 million of derivative receivables related to derivative contracts for our former synthetic fuels businesses (See Note 17A). The increase from income taxes, net was largely due to $252 million in income tax payments made in 2007 related to the sale of natural gas drilling and production business, partially offset by income tax impacts at PEC. The change in accounts payable was primarily related to our divested operations.

In 2009, 2008 and 2007, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries.

INVESTING ACTIVITIES

Net cash used by investing activities for the three years ended December 31, 2009, 2008 and 2007, was $2.532 billion, $2.541 billion and $1.457 billion, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.488 billion and $2.534 billion in 2009 and 2008, respectively, or approximately 100 percent of consolidated capital expenditures in both 2009 and 2008. Capital expenditures at the Utilities are primarily for capacity expansion and normal construction activity and ongoing capital expenditures related to environmental compliance programs.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $1 million in 2009 and $72 million in 2008, cash used in investing activities decreased by $80 million. The decrease in 2009 was primarily due to a $24 million decrease in gross property additions at the Utilities, primarily due to lower spending for environmental compliance projects and the completion of PEF's Bartow Plant repowering project in 2009; a $22 million decrease in nuclear fuel additions; and a $20 million decrease in net purchases of available-for-sale securities and other investments. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $72 million in 2008 and $675 million in 2007, cash used in investing activities increased by $481 million. The increase in 2008 was primarily due to a $341 million increase in gross property additions at the Utilities, primarily at PEF, and a $95 million decrease in net purchases of available-for-sale securities and other investments. The increase in capital expenditures for utility property additions at PEF was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow Plant to more efficient natural gas-burning technology and a $52 million decrease related to the Hines 4 facility.

During 2008, proceeds from sales of discontinued operations and other assets primarily included proceeds of $63 million from the sale of Terminals and Coal Mining (See Notes 3A and 3B).

During 2007, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included approximately $615 million from the sale of PVI's CCO generation assets (See Note 3C), working capital adjustments related to the sale of natural gas drilling and production business, and the sale of poles at Progress Telecommunications Corporation.

FINANCING ACTIVITIES

Net cash provided by financing activities for the three years ended December 31, 2009, 2008 and 2007, was $806 million, $1.248 billion and $195 million, respectively. See Note 11 for details of debt and credit facilities.

The decrease in net cash provided by financing activities for 2009 compared to 2008 is primarily due to a $2.077 billion net decrease in short-term indebtedness, primarily driven by commercial paper repayments and the Parent's repayment of borrowings outstanding under its RCA; partially offset by a $491 million increase in proceeds from the issuance of common stock, primarily related to the Parent's January 2009 common stock offering; a $481 million increase in net proceeds from long-term debt issuances due to the Parent's combined $1.700 billion issuances and PEC's $600 million issuance in 2009 compared to PEF's $1.500 billion issuance and PEC's $325 million issuance in 2008; a $477 million decrease in payments at maturity of long-term debt; and a $118 million decrease in net payments on short-term debt with original maturities greater than 90 days.

The increase in net cash provided by financing activities for 2008 compared to 2007 is primarily due to PEF's $1.475 billion net proceeds and PEC's $322 million net proceeds from the issuance of long-term debt in 2008 discussed below, compared to $739 million in net proceeds in 2007. Additionally, net short-term debt increased in 2008 compared to 2007 due to $600 million in outstanding borrowings under the Parent's RCA, and outstanding commercial paper issuances of $69 million at the Parent, $110 million at PEC and $371 million at PEF, compared to outstanding commercial paper issuances of $201 million at the Parent in 2007. The increase in proceeds from long-term debt issuances was offset by $877 million in long-term debt retirements in 2008; $176 million in payments on short-term debt; and $85 million in cash distributions to owners of minority interests of consolidated subsidiaries primarily related to the settlement of Ceredo Synfuel LLC's (Ceredo) synthetic fuels derivatives contracts (See Note 17A).

Our financing activities are described below.

2010

- On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with proceeds from the $950 million of Senior Notes issued in November 2009.

- Subsequent to December 31, 2009, the Parent has issued approximately 3.6 million shares of common stock resulting in approximately $136 million in proceeds through the IPP.

2009

- On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were approximately $523 million. On February 3, 2009, the Parent used $100 million of the proceeds to reduce its $600 million RCA balance outstanding at December 31, 2008, and the remainder was used for general corporate purposes.

- On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding short-term debt and for general corporate purposes.

- On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.

- On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

- On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to pre-fund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.

- During 2009, we repaid the November 2008 $600 million borrowing under our RCA.

- Progress Energy issued approximately 3.1 million shares of common stock resulting in approximately $100 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 2.5 million shares for proceeds of approximately $100 million issued for the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the IPP. For 2009, the dividends paid on common stock were approximately $693 million.

2008

- On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.

- On March 12, 2008, PEC and PEF amended their RCAs with a syndication of financial institutions to extend the termination date by one year. The extensions were effective for both utilities on March 28, 2008. PEC's RCA is now scheduled to expire on June 28, 2011, and PEF's RCA is now scheduled to expire on March 28, 2011 (See "Credit Facilities and Registration Statements").

- On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

- On April 14, 2008, the Parent amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 2, 2008. The RCA is now scheduled to expire on May 3, 2012 (See "Credit Facilities and Registration Statements").

- On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.

- On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings, and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

- On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. The borrowing was repaid during 2009.

- On November 18, 2008, the Parent, as a well-known seasoned issuer, PEC and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued (See "Credit Facilities and Registration Statements").

- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $132 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 3.1 million shares for proceeds of approximately $131 million issued for the 401(k) and the IPP. For 2008, the dividends paid on common stock were approximately $642 million.

2007

- On July 2, 2007, PEF paid at maturity $85 million of its 6.81% Medium-Term Notes with available cash on hand and commercial paper borrowings.

- On August 15, 2007, due to extreme volatility in the commercial paper market, Progress Energy borrowed $400 million under its $1.13 billion RCA to repay outstanding commercial paper. On October 17, 2007, Progress Energy used $200 million of commercial paper proceeds to repay a portion of the amount borrowed under the RCA. On December 17, 2007, Progress Energy used $200 million of available cash on hand to repay the remaining amount borrowed under the RCA.

- On August 15, 2007, due to extreme volatility in the commercial paper market, PEC borrowed $300 million under its $450 million RCA and paid at maturity $200 million of its 6.80% First Mortgage Bonds. On September 17, 2007, PEC used $150 million of available cash on hand to repay a portion of the amount borrowed under the RCA. On October 17, 2007, PEC repaid the remaining $150 million of its RCA loan using available cash on hand.

- On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.

- On December 10, 2007, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $35 million of its 6.75% Medium-Term Notes with available cash on hand.

- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $151 million in proceeds from its IPP and its equity incentive plans. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million issued for the IPP. For 2007, the dividends paid on common stock were approximately $627 million.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2009, 2008 and 2007. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. At December 31, 2009, we have carried forward $712 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

We expect to be able to meet our future liquidity needs through cash from operations, commercial paper issuance, availability under our credit facilities, long-term debt financings and equity offerings. We may also use periodic ongoing sales of common stock from our IPP and employee benefit and stock option plans to meet our liquidity requirements.

We issue commercial paper to meet short-term liquidity needs. As a result of financial and economic conditions in 2008 and 2009, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. The Parent borrowed $600 million under its RCA in November 2008 and repaid the outstanding balance during 2009 with proceeds from the January 2009 equity issuance, cash on hand and proceeds from commercial paper borrowings. If liquidity conditions deteriorate again and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing under our RCA, issuing short-term notes, issuing long-term debt and/or issuing equity. If our short-term credit ratings are downgraded below Tier 2 (A-2/P-2/F2), we could experience increased volatility in commercial paper durations and interest rates and our access to the commercial paper markets could be negatively impacted. In the event of a downgrade of our senior unsecured credit ratings, our credit facility fees and borrowing rates under our RCA's could increase. We do not expect an increase in such RCA fees to be material. See "Credit Rating Matters" for further discussion regarding credit ratings.

The current RCAs for the Parent, PEC and PEF expire in May 2012, June 2011 and March 2011, respectively. We are currently evaluating options for addressing these upcoming expirations. In the event we enter into new credit facilities, we cannot predict the terms, prices, durations or participants in such facilities.

Progress Energy and its subsidiaries have approximately $12.051 billion in outstanding long-term debt. Currently, approximately $860 million of the Utilities' debt obligations, approximately $620 million at PEC and approximately $240 million at PEF, are tax-exempt auction rate securities insured by bond insurance. These tax-exempt bonds have experienced and continue to experience failed auctions. Assuming the failed auctions persist, future interest rate resets on our tax-exempt auction rate bond portfolio will be dependent on the volatility experienced in the indices that dictate our interest rate resets and/or rating agency actions that may move our tax-exempt bonds below A3/A-. PEC's senior secured debt ratings are currently A1 by Moody's Investors Service, Inc. (Moody's) and A-/Watch Negative by Standard and Poor's Rating Services (S&P). PEF's senior secured debt ratings are currently A1/Watch Negative by Moody's and A-/Watch Negative by S&P. In the event of a one notch downgrade of PEC's and/or

PEF's senior secured debt rating by S&P, the ratings of both utilities' tax-exempt bonds would be below A-, most likely resulting in higher future interest rate resets. In the event of a one notch downgrade by Moody's, PEC's and PEF's tax-exempt bonds will continue to be rated above A3. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations under our defined benefit pension plans. Although a number of factors impact our pension funding requirements, a decline in the market value of these assets may significantly increase the future funding requirements of the obligations under our defined benefit pension plans. We expect to make at least $120 million of contributions directly to pension plan assets in 2010 (See Note 16).

As discussed in "Strategy," "Liquidity and Capital Resources," "Capital Expenditures," and in "Other Matters – Environmental Matters," over the long term, compliance with environmental regulations and meeting the anticipated load growth at the Utilities as described under "Other Matters – Increasing Energy Demand" will require the Utilities to make significant capital investments. These anticipated capital investments are expected to be funded through a combination of cash from operations and issuance of long-term debt, preferred stock and/or common equity, which are dependent on our ability to successfully access capital markets. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation. As discussed in "Other Matters – Nuclear – Potential New Construction," PEF expects its capital expenditures for the Levy project will be significantly less in the near term than previously planned in light of a regulatory schedule shift and other factors.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and consumption of the fuel, any realized gains or losses are passed through the fuel cost-recovery clause. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted the amount of collateral posted with counterparties. At February 19, 2010, we had posted approximately $168 million of cash collateral compared to $146 million of cash collateral posted at December 31, 2009. The majority of our financial hedge agreements will settle in 2010 and 2011. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity. In addition, as discussed in "Credit Rating Matters," if our credit ratings are downgraded, we may have to post additional cash collateral for derivatives in a liability position.

The amount and timing of future sales of debt and equity securities will depend on market conditions, operating cash flow and our specific needs. We may from time to time sell securities beyond the amount immediately needed to meet capital requirements in order to allow for the early redemption of long-term debt, the redemption of preferred stock, the reduction of short-term debt or for other corporate purposes.

At December 31, 2009, the current portion of our long-term debt was $406 million. On January 15, 2010, we funded the $100 million Series A Floating Rate Notes maturity with proceeds from the Parent's November 2009 $950 million long-term debt issuance, and we expect to fund the remaining $306 million with a combination of cash from operations, commercial paper borrowings and long-term debt.

See "Credit Rating Matters" for information regarding recent rating actions.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, including nuclear cost recovery, as discussed in Note 7 and "Other Matters – Regulatory Environment," and filings for recovery of environmental costs, as discussed in Note 21 and in "Other Matters – Environmental Matters," may impact our future liquidity and financing activities. The impacts of these matters, including the timing of recoveries from ratepayers, can be both a source of and a use of future liquidity resources. Regulatory developments expected to have a material impact on our liquidity are discussed below.

As discussed further in Note 7 and in “Other Matters – Regulatory Environment,” the North Carolina, South Carolina and Florida legislatures passed energy legislation that became law in recent years. These laws may impact our liquidity over the long term, including, among others, provisions regarding cost recovery, mandated renewable portfolio standards, DSM and energy efficiency.

PEC Cost-Recovery Clause

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On June 19, 2009, the SCPSC approved a settlement agreement filed jointly by PEC and the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC’s proposed rate reduction of approximately $13 million, which went into effect July 1, 2009.

On June 4, 2009, PEC filed with the North Carolina Utilities Commission (NCUC) for a decrease in the fuel rate charged to its North Carolina ratepayers. The filing was updated on August 17, 2009. PEC asked the NCUC to approve a $14 million decrease in the fuel rates driven by declining fuel prices, which went into effect December 1, 2009. At December 31, 2009, PEC’s North Carolina deferred fuel balance was $148 million, of which $62 million is expected to be collected after 2010.

PEC Other Matters

On October 13, 2008, the NCUC issued a Certificate of Public Convenience and Necessity allowing PEC to proceed with plans to construct an approximately 600-MW combined cycle dual fuel capable generating facility at its Richmond County generation site to provide additional generating and transmission capacity to meet the growing energy demands of southern and eastern North Carolina. PEC expects that the new generating and transmission capacity will be online by the second quarter of 2011.

As discussed in Note 7 and in “Other Matters – Environmental Matters,” on October 22, 2009, the NCUC issued an order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. We intend to continue to depreciate the three coal-fired units at their current depreciation rate until PEC’s next depreciation study. PEC projects that the generating facility would be in service by January 2013. The filed estimate of capital expenditures, net of AFUDC – borrowed funds for the new generating facility is approximately $800 million. PEC modified its Clean Smokestacks Act compliance plan for the change in fuel source and removed retrofitting PEC’s Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC, which decreased estimated capital expenditures to meet the Clean Smokestacks Act emission targets by 2013 to $1.1 billion from $1.4 billion. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

In accordance with the October 2009 NCUC order, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. We intend to continue to depreciate the coal-fired units at their current depreciation rate until PEC's next depreciation study. On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. The filed estimate of capital expenditures, net of AFUDC – borrowed funds for the new generating facility is approximately $600 million. PEC projects that the generating facility would be in service by late 2013 or early 2014.

PEF Base Rates

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for

PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. The interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual O&M costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options.

PEF Cost-Recovery Clauses

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices. The approval reduced customers' fuel charges starting with the first billing cycle of April 2009.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by $105 million, thereby decreasing residential electric bills by $3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. On October 23, 2009, PEF filed a $3 million cost adjustment with the FPSC, which reduced the capacity cost-recovery clause (CCRC) rate by $0.08 per 1,000 kWh from the original September 14, 2009 cost adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

In addition, on August 28, 2009 and as updated on October 27, 2009, PEF filed a request to increase the ECRC residential rate. Also, on September 14, 2009, PEF filed a request to increase the ECCR residential rate. The FPSC approved a combined $37 million increase in PEF's ECRC and ECCR clauses on November 2, 2009, to be effective January 1, 2010.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. The FPSC has approved cost recovery of PEF's prudently incurred costs necessary to achieve its integrated strategy to address compliance with CAIR, the Clean Air Mercury Rule (CAMR) and the Clean Air Visibility Rule (CAVR) through the ECRC (See "Other Matters – Environmental Matters" for discussion regarding the CAIR, CAMR and CAVR).

Nuclear Cost Recovery

PEF is allowed to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances on an annual basis through the CCRC. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs through the CCRC, and found that PEF's project management, contracting, and oversight controls were reasonable and prudent. As discussed in Note 7, on October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced customers' nuclear cost-recovery charge starting with the first billing cycle of April 2009.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million through the nuclear cost-recovery clause of the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt and equity issuances provided the funding for our capital expenditures, including environmental compliance and other utility property additions, nuclear fuel expenditures and non-utility property additions during 2009.

As shown in the table that follows, we expect the majority of our capital expenditures to be incurred at our regulated operations. We expect to fund our capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or common equity. In addition, we have $2.030 billion in credit facilities that support the issuance of commercial paper. Access to the commercial paper market provides additional liquidity to help meet working capital requirements. AFUDC – borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	**2009**	2010	2011	2012
Regulated capital expenditures	**$ 1,995**	$ 2,160	$ 2,120	$ 1,810
Nuclear fuel expenditures	**200**	230	300	260
AFUDC-borrowed funds	**(37)**	(30)	(40)	(40)
Other capital expenditures	**7**	30	30	30
Total before potential nuclear construction	**2,165**	2,390	2,410	2,060
Potential nuclear construction [(a)]	**291**	100 – 150	60 – 70	60 –70
Total	**$ 2,456**	$2,490 – 2,540	$2,470 – 2,480	$2,120 – 2,130

(a) Expenditures for potential nuclear construction are net of AFUDC – borrowed funds.

Regulated capital expenditures for 2010, 2011 and 2012 in the previous table include approximately $130 million, $40 million and $100 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2010, 2011 and 2012 include $20 million, $40 million and $50 million, respectively, at PEC. Forecasted environmental compliance capital expenditures for 2010 and 2012 include $110 million and $50 million, respectively, at PEF. No environmental compliance capital expenditures are forecasted for PEF in 2011. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

Potential nuclear construction expenditures, which are primarily for PEF's Levy, include development, licensing and equipment. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement. (See discussion under "Other Matters – Nuclear – Potential New Construction"). The forecasted capital expenditures presented in the previous table reflect the anticipated impact of such amendment. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and/or exit costs cannot be determined at this time and, accordingly, are not included in the previous table. Potential nuclear construction expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions Forecasted potential nuclear construction expenditures for 2010, 2011 and 2012 include approximately $70 million, $30 million and $30 million, respectively, of preconstruction expenditures, which are eligible for recovery under Florida's nuclear cost-recovery rule.

All projected capital and investment expenditures are subject to periodic review and revision and may vary significantly depending on a number of factors including, but not limited to, industry restructuring, regulatory constraints, market volatility and economic trends.

CREDIT FACILITIES AND REGISTRATION STATEMENTS

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the table below, of which $100 million was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

2009					
(in millions)	**Description**	**Total**	**Outstanding [a]**	**Reserved [b]**	**Available**
Parent	**Five-year (expiring 5/3/12)**	**$ 1,130**	**$ –**	**$ 177**	**$ 953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$ 2,030**	**$ –**	**$ 177**	**$ 1,853**

2008					
(in millions)	Description	Total	Outstanding [a]	Reserved [b]	Available
Parent	Five-year (expiring 5/3/12)	$ 1,130	$ 600	$ 99	$ 431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$ 2,030	$ 600	$ 580	$ 850

(a) The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.

(b) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had a total amount of $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

All of the revolving credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities. See Note 11 for additional discussion of our credit facilities.

The RCAs provide liquidity support for issuances of commercial paper and other short-term obligations. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings. Fees and interest rates under the Parent's RCA are based upon the credit rating of the Parent's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2/Watch Negative by Moody's and BBB/Watch Negative by S&P. Fees and interest rates under PEC's RCA are based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB+/Watch Negative by S&P. Fees and interest rates under PEF's RCA are based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3/Watch Negative by Moody's and BBB+/Watch Negative by S&P.

All of the credit facilities include defined maximum total debt-to-total capital ratio (leverage) covenants, which we were in compliance with at December 31, 2009. We are currently in compliance and expect to continue to be in compliance with these covenants. See Note 11 for a discussion of the credit facilities' financial covenants. At December 31, 2009, the calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, are as disclosed in Note 11.

The Parent, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various securities, including senior debt securities, junior subordinated debentures, common stock, preferred stock, stock purchase contracts, stock purchase units, and trust preferred securities and guarantees.

PEC has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

PEF has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

Both PEC and PEF can issue first mortgage bonds under their respective first mortgage bond indentures based on property additions, retirements of First Mortgage Bonds and the deposit of cash, provided that adjusted net earnings are at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. At December 31, 2009, PEC and PEF could issue up to approximately $6.0 billion and $2.6 billion of first mortgage bonds, respectively, based on property additions and retirements of previously issued first mortgage bonds. At December 31, 2009, PEC's and PEF's ratios of adjusted net earnings to annual interest requirement on outstanding first mortgage bonds were 4.9 times and 3.4 times, respectively.

CAPITALIZATION RATIOS

The following table shows our capitalization ratios at December 31:

	2009	2008
Total equity	**42.3%**	41.9%
Preferred stock	**0.4%**	0.5%
Total debt	**57.3%**	57.6%

CREDIT RATING MATTERS

At February 22, 2010, the major credit rating agencies rated our securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Long-Term Ratings			
Parent			
Outlook/Watch	Watch Negative [(a)]	Watch Negative [(b)]	Stable
Corporate credit rating	n/a	BBB+	BBB
Senior unsecured debt	Baa2	BBB	BBB
PEC			
Outlook/Watch	Stable	Watch Negative [(b)]	Stable
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Subordinate debt	Baa1	n/a	n/a
Preferred stock	Baa2	BBB-	BBB+
PEF			
Outlook/Watch	Watch Negative [(a)]	Watch Negative [(b)]	Watch Negative [(c)]
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Preferred stock	Baa2	BBB-	BBB+
Florida Progress Corporation (FPC) Capital I			
Outlook/Watch	Watch Negative [(a)]	Watch Negative [(b)]	Watch Negative [(c)]
Quarterly Income Preferred Securities [(d)]	Baa2	BBB-	BBB+
Short-Term Ratings			
Parent			
Watch	Watch Negative [(a)]	N/A	N/A
Commercial Paper	P-2	A-2	F2
PEC			
Watch	N/A	N/A	N/A
Commercial Paper	P-2	A-2	F1
PEF			
Watch	N/A	N/A	Watch Negative [(c)]
Commercial Paper	P-2	A-2	F1

[(a)] On January 19, 2010, Moody's placed these ratings on review for possible downgrade.

[(b)] On January 14, 2010, S&P placed these ratings on CreditWatch Negative.

[(c)] On January 12, 2010, Fitch placed these ratings on Rating Watch Negative.
[(d)] Guaranteed by the Parent and FPC.

These ratings reflect the current views of these rating agencies, and no assurances can be given that these ratings will continue for any given period of time. However, we monitor our financial condition as well as market conditions that could ultimately affect our credit ratings.

On August 3, 2009, Moody’s raised the senior secured debt rating of both PEC and PEF to A1 from A2 as a result of Moody’s reevaluating its notching criteria for investment-grade regulated utilities to reflect the historical lower default rates for regulated utilities than for non-financial, non-utility corporate issuers.

On January 12, 2010, Fitch placed ratings of PEF and FPC Capital I on Rating Watch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Fitch cited lower cash flow expectations and increased regulatory risk as drivers for the rating action.

On January 14, 2010, S&P placed ratings of Progress Energy, Inc. and its subsidiaries, including PEC, PEF, FPC Capital I and Florida Progress Corp., on CreditWatch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. At the same time, S&P affirmed the ‘A-2’ short-term ratings on Progress Energy, Inc., PEC and PEF.

On January 19, 2010, Moody’s placed the long-term ratings of Progress Energy, Inc. and PEF on review for possible downgrade as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Moody’s also placed the short-term rating for commercial paper of Progress Energy, Inc. on review for possible downgrade. At the same time, Moody’s affirmed the ratings and stable outlook of PEC.

As noted above, the three rating agencies cited increased regulatory risk and PEF’s rate case outcome as the key driver of the ratings actions. Credit rating changes could be made after the agencies have completed their reviews of PEF’s rate order and our response to the decision.

Credit rating downgrades could negatively impact our ability to access the capital markets and respond to major events such as hurricanes. Our cost of capital could also be higher, which could ultimately increase prices for our customers. It is important for us to maintain our credit ratings and have access to the capital markets in order to reliably serve customers, invest in capital improvements and prepare for our customer’s future energy needs (See Item 1A, “Risk Factors”).

As discussed in Note 17C, credit rating downgrades could also require us to post additional cash collateral for commodity hedges in a liability position as certain derivative instruments require us to post collateral on liability positions based on our credit ratings.

On January 22, 2010, Fitch lowered the rating on PEC’s, PEF’s and FPC Capital I’s preferred securities to BBB+ from A- as a result of the implementation of Fitch’s revised guidelines for rating preferred stock and hybrid securities.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

Our off-balance sheet arrangements and contractual obligations are described below.

GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At December 31, 2009, we have issued $406 million of guarantees for future financial or performance assurance, including $11 million at PEC. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 23). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

At December 31, 2009, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations as discussed in Note 22C.

MARKET RISK AND DERIVATIVES

Under our risk management policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented in the following table are estimates and therefore will likely differ from actual purchase amounts. Further disclosure regarding our contractual obligations is included in the respective notes to the Consolidated Financial Statements. We take into consideration the future commitments when assessing our liquidity and future financing needs.

The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2009, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt [(a)] (See Note 11)	$ 12,515	$ 406	$ 1,950	$ 1,125	$ 9,034
Interest payments on long-term debt [(b)]	10,077	707	1,289	1,073	7,008
Capital lease obligations [(c)] (See Note 22B)	484	34	67	74	309
Operating leases [(c)] (See Note 22B)	1,430	35	83	181	1,131
Fuel and purchased power [(d)] (See Note 22A)	24,070	3,092	5,202	3,923	11,853
Other purchase obligations [(e)] (See Note 22A)	9,749	1,872	3,288	2,883	1,706
Minimum pension funding requirements [(f)]	794	74	353	229	138
Other postretirement benefits [(g)] (See Note 16A)	397	34	73	79	211
Uncertain tax positions [(h)] (See Note 14)	–	–	–	–	–
Other commitments [(i)]	105	13	26	26	40
Total	$ 59,621	$ 6,267	$ 12,331	$ 9,593	$ 31,430

(a) Our maturing debt obligations are generally expected to be repaid with cash from operations or refinanced with new debt issuances in the capital markets.

(b) Interest payments on long-term debt are based on the interest rate effective at December 31, 2009.

(c) Amounts include certain related executory cost commitments.

(d) Essentially all fuel and certain purchased power costs incurred by the Utilities are recovered through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support.

(e) Amounts primarily relate to an EPC agreement that PEF entered into in December 2008 for two nuclear units planned for construction at Levy. The contractual obligations presented are in accordance with the existing terms of the EPC agreement, which assumes the original construction schedule and 100 percent ownership by PEF. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the EPC agreement (See discussion under "Other Matters – Nuclear – Potential New Construction.") We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in this table.

(f) Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

(g) Represents projected benefit payments for a total of 10 years related to our postretirement health and life plans. These amounts are subject to change based on factors such as experienced claims and general health care cost trends.

(h) Uncertain tax positions of $160 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. It is reasonably possible that the total amounts of unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements.

(i) By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

OTHER MATTERS

REGULATORY ENVIRONMENT

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, the SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the NRC and other federal and state agencies common to the utility business. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the Utilities are permitted to earn, are subject to the approval of one or more of these governmental agencies.

To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give retail ratepayers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. We cannot anticipate when, or if, any of these states will move to increase retail competition in the electric industry.

The American Recovery and Reinvestment Act, signed into law in February 2009 contains provisions promoting energy efficiency and renewable energy, including $3.4 billion in Smart Grid technology development grants, $615 million for Smart Grid storage, monitoring and technology viability, $6.3 billion for energy-efficiency and conservation grants and $2 billion in tax credits for the purchase of plug-in electric vehicles. In August 2009, we submitted our application to the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our investment in Smart Grid-related technologies in the Carolinas and Florida. On October 27, 2009, the DOE notified us of our selection for Smart Grid award negotiations. We are now awaiting further questions and comments from the DOE on our Smart Grid application. The submission of an application and the notification for award negotiations are not a commitment to accept federal funds but are necessary steps to keep the option open. We are currently evaluating the provisions of the law and assessing the conditions imposed by participation in the incentive programs. Also, the Obama administration has announced a goal of encouraging investment in transmission and promoting renewable resources while also pricing GHG emissions and setting a federal requirement for renewable energy.

On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce GHG emissions as well as a national renewable energy portfolio standard (REPS). The bill also calls for investment in the electric grid, more production and utilization of electric vehicles and improvements in energy efficiency in buildings and appliances. The full impact of the legislation, if enacted into law, cannot be determined at this time and will depend upon changes made to its provisions during the legislative process and the manner in which key provisions are implemented, including the regulation of carbon. The U.S. Senate is considering similar proposals. The full impact of final legislation, if enacted, and additional regulation resulting from these and other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time, for which the Utilities would seek corresponding rate recovery.

Current retail rate matters affected by state regulatory authorities are discussed in Notes 7B and 7C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects on our consolidated financial statements.

On July 31, 2009, the governor of North Carolina signed into law a bill that includes three key provisions that may impact PEC. First, the legislation accelerates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal unit at that specific site. Pursuant to the legislation, PEC requested and received approval from the NCUC to pursue construction of a new 950-MW natural gas plant (see further discussion in Note 7B and "Other Matters – Environmental Matters"). Second, a recovery mechanism is provided for utilities if they invest in zero emissions renewable energy facilities within the next five years. Finally, the legislation changes the state's Dam Safety Act such that dams at utility coal-fired power plants, including dams for ash ponds, will be subject to the Act's applicable provisions, including state inspection as of January 1, 2010.

Florida energy law enacted in 2008 includes provisions that would, among other things, (1) help enhance the ability to cost-effectively site transmission lines; (2) require the FPSC to develop a renewable portfolio standard that the

FPSC would present to the legislature for ratification in 2009; (3) direct the Florida Department of Environmental Protection (FDEP) to develop rules establishing a cap-and-trade program to regulate GHG emissions that the FDEP would present to the legislature no earlier than January 2010 for ratification by the legislature; and (4) establish a new Florida Energy and Climate Commission as the principal governmental body to develop energy and climate policy for the state and to make recommendations to the governor and legislature on energy and climate issues. In complying with the provisions of the law, PEF would be able to recover its reasonable prudent compliance costs. However, until these agency actions are finalized, we cannot predict the costs of complying with the law.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of GHG emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of GHGs for Florida utilities. The standard will require, at a minimum, the following three reduction milestones: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; and by 2050, emissions not greater than 20 percent of Year 1990 utility sector emissions. To date, the FDEP has held three rulemaking workshops on the GHG cap-and-trade rulemaking. Rulemaking is expected to continue through 2010, and the rule requires legislative ratification before implementation.

The executive orders also requested that the FPSC initiate a rulemaking by September 1, 2007, that would (1) require Florida utilities to produce at least 20 percent of their electricity from renewable sources; (2) reduce the cost of connecting solar and other renewable energy technologies to Florida’s power grid by adopting uniform statewide interconnection standards for all utilities; and (3) authorize a uniform, statewide method to enable residential and commercial customers who generate electricity from onsite renewable technologies of up to 1 MW in capacity to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering). On January 12, 2009, the FPSC approved a draft Florida renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida renewable portfolio standard rule to the Florida legislature in February 2009, but the legislature did not take action in the 2009 session. We cannot predict the outcome of this matter.

We cannot predict the costs of complying with the laws and regulations that may ultimately result from these executive orders. Our balanced solution, as described in “Energy Demand,” includes greater investment in energy efficiency, renewable energy and state-of-the-art generation and demonstrates our commitment to environmental responsibility.

North Carolina energy law enacted in 2007 includes provisions for a North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), expansion of the definition of the traditional fuel clause and recovery of the costs of new DSM and energy-efficiency programs through an annual DSM clause. On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina’s 2007 energy law. The rules include filing requirements regarding NC REPS compliance and inclusion in the Utility’s integrated resource plan. The order also establishes a schedule and filing requirements for DSM and energy-efficiency cost recovery and financial incentives. Rates for the DSM and energy-efficiency clause and the NC REPS clause will be set based on projected costs with true-up provisions. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results.

ENERGY DEMAND

Implementing state and federal energy policies, promoting environmental stewardship and providing reliable electricity to meet the anticipated long-term growth within the Utilities’ service territories will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our energy-efficiency programs; (2) investing in the development of alternative energy resources for the future; and (3) operating state-of-the-art plants that produce energy cleanly and efficiently by modernizing existing plants and pursuing options for building new plants and associated transmission facilities.

We are actively pursuing expansion of our DSM, energy-efficiency and conservation programs because energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. DSM programs include programs and initiatives that shift the timing of electricity use from peak to nonpeak periods, such as load management, electricity system and operating controls, direct load control, interruptible load, and electric system equipment and operating controls. We provide our residential customers with home energy audits and offer energy-efficiency programs that provide incentives for customers to implement measures that reduce energy use. For business customers, we also provide energy audits and other tools, including an interactive Internet Web site with online calculators, programs and efficiency tips, to help them reduce their energy use.

We are actively engaged in a variety of alternative energy projects to pursue the generation of electricity from swine waste and other plant or animal sources, biomass, solar, hydrogen, and landfill-gas technologies. Among our projects, we have executed contracts to purchase approximately 250 MW of electricity generated from biomass and up to 60 MW of electricity generated from municipal solid waste sources. The majority of these projects should be online within the next five years. In addition, we have executed purchased power agreements for approximately 10 MW of electricity generated from solar photovoltaic generation as part of the NC REPS. The majority of these projects are online and the remainder should be online by early 2010. Additionally, customers across our service territory have connected approximately 4 MW of solar photovoltaic energy systems to our grid. In June 2009, we expanded our solar energy strategy to include a range of new solar incentives and programs, which are expected to increase our use of solar energy by more than 100 MW over the next decade.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated long-term growth in our service territories, we estimate that we will require new generation facilities in both Florida and the Carolinas toward the end of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and gas technologies. At this time, no definitive decisions have been made to construct new nuclear plants.

In 2009, PEC announced a coal-to-gas modernization strategy whereby the 11 remaining coal-fired generating facilities in North Carolina that do not have scrubbers would be retired prior to the end of their useful lives and their approximately 1,500 MW of generating capacity replaced with new natural gas-fueled facilities. The coal-fired units will be retired by the end of 2017. PEC has received approval from the NCUC for construction of a 950-MW natural gas-fueled generating facility at a site in Wayne County, N.C., to be placed in service in January 2013. PEC has requested approval from the NCUC to construct a 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C. The facility is projected to be placed in service in late 2013 or early 2014. PEC will continue to operate three coal-fired plants in North Carolina after 2017. PEC has invested more than $2 billion in installing state-of-the-art emission controls at the Roxboro, Mayo and Asheville Plants. Emissions of NOx, SO_2, mercury and other pollutants have been reduced significantly at those sites.

As authorized under the Energy Policy Act of 2005 (EPACT), on October 4, 2007, the DOE published final regulations for the disbursement of up to $13 billion in loan guarantees for clean-energy projects using innovative technologies. The guarantees, which will cover up to 100 percent of the amount of any loan for no more than 80 percent of the project cost, are expected to spur development of nuclear, clean-coal and ethanol projects.

In 2008, Congress authorized $38.5 billion in loan guarantee authority for innovative energy projects. Of the total provided, $18.5 billion is set aside for nuclear power facilities, $2 billion for advanced nuclear facilities for the "front-end" of the nuclear fuel cycle, $10 billion for renewable and/or energy-efficient systems and manufacturing and distributed energy generation/transmission and distribution, $6 billion for coal-based power generation and industrial gasification at retrofitted and new facilities that incorporate carbon capture and sequestration or other beneficial uses of carbon, and $2 billion for advanced coal gasification. In June 2008, the DOE announced solicitations for a total of up to $30.5 billion of the amount authorized by Congress in federal loan guarantees for projects that employ advanced energy technologies that avoid, reduce or sequester air pollutants or greenhouse gas emissions and advanced nuclear facilities for the “front-end” of the nuclear fuel cycle.

PEF submitted Part I of the Application for Federal Loan Guarantees for Nuclear Power Facilities on September 29, 2008, for Levy. PEF was one of 19 applicants that submitted Part I of the application. The program requires that the guarantee be in a first lien position on all assets of the project, which conflicts with PEF’s current mortgage. Obtaining the required approval to amend the current mortgage from 100 percent of PEF’s current bondholders would be unlikely, and current secured debt of $4.0 billion would need to be refinanced with unsecured debt to meet the requirements of the guarantee. In addition, the costs associated with obtaining the loan guarantee are unclear. PEF decided not to pursue the loan guarantee program and did not submit Part II of the application, which was due on December 19, 2008. However, this decision does not preclude PEF from revisiting the program at a later date if there are changes to the program. We cannot predict if PEF will pursue this program further.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. EPACT provides an annual tax credit of 1.8 cents per kWh for nuclear facilities for the first eight years of operation. The credit is limited to the first 6,000 MW of new nuclear generation in the United States and has an annual cap of $125 million per 1,000 MW of national MW capacity limitation allocated to the unit. In April 2006, the IRS provided interim guidance that the 6,000 MW of production tax credits generally will be allocated to new nuclear facilities that filed license applications with the NRC by December 31, 2008, had poured safety-related concrete prior to January 1, 2014, and were placed in service before January 1, 2021. There is no guarantee that the interim guidance will be incorporated into the final regulations governing the allocation of production tax credits. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant we construct would qualify for these or other incentives. We cannot predict the outcome of this matter.

NUCLEAR

Nuclear generating units are regulated by the NRC. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs, uprates and certain other modifications.

CR3 is currently undergoing an extended outage for normal refueling and maintenance as well as a project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure. PEF is finalizing the root cause determination of the delamination event and the necessary repair plans. At present, PEF does not have a firm return to service date for CR3, finalized repair estimates and replacement power costs, or the impact of insurance recovery. However, the costs to repair the delamination and associated costs of an outage extension, such as fuel, purchased power and maintenance, could be material. Based on the current understanding of the cause of the delamination event and the conceptual repair strategy, PEF expects that CR3 will return to service in mid-2010.

The NRC operating licenses for PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On March 9, 2009, the NRC docketed, or accepted for review, PEF's application for a 20-year renewal on the operating license for CR3, which would extend the operating license through 2036, if approved. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will renew the license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

POTENTIAL NEW CONSTRUCTION

While we have not made a final determination on nuclear construction, we continue to take steps to keep open the option of building a plant or plants. During 2008, PEC and PEF filed COL applications to potentially construct new nuclear plants in North Carolina and Florida. The NRC estimates that it will take approximately three to four years to review and process the COL applications. We have focused on the potential construction in Florida given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions as well as existing state legislative policy that is supportive of nuclear projects.

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. On April 17, 2008, the NRC docketed, or accepted for review, the Harris application.

Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. No petitions to intervene have been admitted in the Harris COL application. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until at least 2019 (See "Energy Demand" above).

On December 12, 2006, we announced that PEF selected a greenfield site at Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. In 2007, both the Levy County Planning Commission and the Board of Commissioners voted unanimously in favor of PEF's requests to change the comprehensive land use plan. On May 29, 2008, the Florida Department of Community Affairs issued its final determination that the amendments to the Levy County Comprehensive Plan are in compliance with land use regulations.

In 2008, PEF submitted filings for two key state approvals. First, on March 11, 2008, PEF filed a Petition for a Determination of Need for Levy with the FPSC. The FPSC issued a final order granting PEF's petition for Levy on August 12, 2008. Second, on June 2, 2008, PEF filed its application for site certification with the FDEP. Certification addresses permitting, land use and zoning, and property interests and replaces state and local permits. Certification grants approval for the location of the power plant and its associated facilities such as roadways and electrical transmission lines carrying power to the electrical grid, among others. Certification does not include licenses required by the federal government. On January 12, 2009, the FDEP filed a favorable staff analysis report in advance of certification hearings. The technical proceedings concluded on March 12, 2009, and the administrative law judge issued a recommended order on certification on May 15, 2009. The Power Plant Siting Board, comprised of the governor and the Cabinet, issued the Levy certification on August 26, 2009.

On July 30, 2008, PEF filed its COL application with the NRC for two reactors. PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. On October 6, 2008, the NRC docketed, or accepted for review, the Levy application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. One joint petition to intervene in the licensing proceeding was filed with the NRC within the 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. On April 20-21, 2009, the Atomic Safety Licensing Board (ASLB) heard oral arguments on whether any of the joint interveners' proposed contentions will be admitted in the Levy COL proceeding. On July 8, 2009, the ASLB issued a decision accepting three of the 12 contentions submitted. The admitted contentions involved questions about the storage of low-level radioactive waste, the potential impacts of plant construction and operation on the aquifer and surrounding waters and the potential impact of salt water drift from cooling tower operation. PEF's appeal of the ASLB's decision was denied and a hearing on the contentions will be conducted in 2011. Other COL applicants have received similar petitions raising similar potential contentions. We cannot predict the outcome of this matter.

PEF expects a schedule shift for the commercial operation dates of the Levy nuclear units. PEF's initial schedule anticipated the ability to perform certain site work pursuant to a Limited Work Authorization from the NRC prior to COL receipt. However, in 2009, the NRC Staff determined that certain schedule-critical work that PEF had proposed to perform within the Limited Work Authorization scope will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work will be shifted until after COL issuance. This factor alone resulted in a minimum 20-month schedule shift later than the originally anticipated 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions, and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan regarding Levy.

As discussed below, the schedule shift will reduce the near-term capital expenditures for the project and also reduce the near-term impact on customer rates. The schedule shift will also allow more time for certainty around federal climate change policy, which is currently being debated. We believe that continuing, although at a slower pace than initially anticipated, is a reasonable and prudent course at this early stage of the project. We still consider Levy as

PEF's preferred baseload generation option, taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including public, regulatory and political support; adequate financial cost-recovery mechanisms; customer rate impacts, project feasibility and availability and terms of capital financing.

PEF signed the EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The total escalated cost for the two generating units was estimated in PEF's petition for the Determination of Need for Levy to be approximately $14 billion. This total cost estimate includes land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion was estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. We anticipate amending the EPC agreement due to the schedule shift previously discussed but cannot predict the impact such amendment might have on the project's cost, if any.

Florida regulations allow investor-owned utilities such as PEF to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balance of a nuclear power plant prior to commercial operation. The costs are recovered on an annual basis through the CCRC. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility.

In 2008, PEF sought and received approval from the FPSC to recover Levy preconstruction and carrying charges of $357 million as well as site selection costs of $38 million through the 2009 CCRC. In 2009, PEF received approval to defer until 2010 the recovery of $198 million of these costs (See Note 7C). On October 16, 2009, the FPSC approved the recovery of $201 million of preconstruction costs, carrying costs and incremental O&M incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with Levy as part of the total $207 million FPSC-approved recovery of nuclear costs through the 2010 CCRC (See Note 7C).

At December 31, 2009, PEF's unrecovered investment in Levy totaled $404 million, of which $358 million is recoverable in retail rates through the Florida nuclear cost-recovery rules, including $296 million of construction work in progress, of which $274 million was reflected as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs and $22 million was reflected as a deferred fuel regulatory asset. The remaining $46 million is apportioned to PEF's wholesale jurisdiction and would be recovered through PEF's wholesale rates. If Levy is deferred or cancelled, PEF may incur additional contract suspension, termination and/or exit costs that would increase its unrecovered investment. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time.

PEC's jurisdictions also have laws encouraging nuclear baseload generation. South Carolina law includes provisions for cost-recovery mechanisms associated with nuclear baseload generation. North Carolina law authorizes the NCUC to allow annual prudence reviews of baseload generating plant construction costs and inclusion of construction work in progress in rate base with corresponding rate adjustment in a general rate case while a baseload generating plant is under construction (See "Other Matters – Regulatory Environment").

SPENT NUCLEAR FUEL MATTERS

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. We have a contract with the DOE for the future storage and disposal of our spent nuclear fuel. Delays have occurred in the DOE's proposed permanent repository to be located at Yucca Mountain, Nev. The Obama administration has determined that Yucca Mountain, Nev., is not a workable option for a nuclear waste repository and will discontinue its program to construct a repository at this site in 2010. The administration will continue to explore alternatives. Debate surrounding any new strategy likely will address centralized interim storage, permanent storage at multiple sites and/or spent nuclear fuel reprocessing. We cannot predict the outcome of this matter.

The NRC has proposed revisions to its waste confidence findings that would remove the provisions stating that the NRC's confidence in waste management, underlying the licensing of reactors, is based in part on a permanent repository being in operation by 2025. Instead, the NRC states that repository capacity will be available within 50 to 60 years beyond the licensed operation of all reactors, and that used fuel generated in any reactor can be safely stored on site without significant environmental impact for at least 60 years beyond the licensed operation of the reactor. We cannot predict the outcome of this matter.

On September 15, 2009, the NRC proposed licensing requirements for storage of spent nuclear fuel, which would clarify the term limits for specific licenses for independent spent fuel storage installations and for certificates of compliance for spent nuclear fuel storage casks. The agency proposal would formalize the site-by-site exemption the NRC has used for renewal applications requesting more than the current 20-year duration. The initial and renewal terms of a specific installation license would be effective for a period of up to 40 years. Similarly, the proposed rule would allow applicants for certificates of compliance to request initial and renewal terms of up to 40 years, provided they can demonstrate that all design requirements are satisfied for the requested term. We cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation and/or expansion of on-site dry cask storage facilities at PEC's Robinson Nuclear Plant (Robinson), Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated by their respective systems through the expiration of the operating licenses, including any license renewals, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its renewed operating license.

See Note 22D for information about the complaint filed by the Utilities in the United States Court of Federal Claims against the DOE for its failure to fulfill its contractual obligation to receive spent fuel from nuclear plants. Failure to open the Yucca Mountain or other facility would leave the DOE open to further claims by utilities.

ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liability. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida or potentially responsible parties (PRP) groups. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. Hazardous and solid waste management matters are discussed in detail in Note 21A.

We accrue costs to the extent our liability is probable and the costs can be reasonably estimated. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates could change and additional losses, which could be material, may be incurred in the future.

As discussed in “Other Matters – Regulatory Environment,” as of January 1, 2010, dams at utility fossil-fired power plants, including dams for ash ponds, are subject to the North Carolina Dam Safety Act’s applicable provisions, including state inspection. Until the state agency responsible for dam safety inspects each of the affected dams, we cannot predict if additional safety-related measures will be required. However, these dams have been subject to periodic third-party inspection in accordance with prior applicable requirements.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products, primarily ash, from each of the Utilities’ coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary.

In June 2009, the EPA evaluated information about ash impoundment dams nationwide and posted a listing of 44 utility ash impoundment dams that are considered to have “high hazard potential,” including two of PEC’s ash impoundment dams. A “high hazard potential” rating is not related to the stability of those ash ponds but to the potential for harm should the impoundment dam fail. As noted above, all of the dams at PEC’s coal ash ponds have been subject to periodic third-party inspection. In September 2009, the EPA rated the 44 “high hazard potential” impoundments, as well as other impoundments, from “unsatisfactory” to “satisfactory” based on their structural integrity and associated documentation.

Only dams rated as “unsatisfactory” would be considered to pose an immediate safety threat, but none of the facilities received an “unsatisfactory” rating. In total, six of PEC’s ash pond dams, including one “high hazard potential” impoundment, were rated as “poor” based on the contract inspector’s desire to see additional documentation and their evaluations of vegetation management and minor erosion control. Inspectors applied the same criteria to both active and inactive ash ponds, despite the fact that most of the inactive ash impoundments no longer hold water and do not pose a risk of breaching and spilling. PEC has completed several of the recommendations for the active ponds and other recommendations are under way. We are working with the North Carolina Dam Safety program to evaluate the remaining recommendations. We do not expect mitigation of these issues to have a material impact on our results of operations.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which likely would result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require reductions in air emissions of NOx, sulfur dioxide (SO_2), CO_2 and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment installed pursuant to the provisions of CAIR, CAVR and mercury regulations, which are discussed below, may address some of the issues outlined above. PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, CAVR and mercury regulation (see discussion of the court decisions that impacted the

CAIR, the delisting determination and the CAMR below). The CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. On March 31, 2009, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately $1.4 billion at the time of the filing. As discussed in "Other Matters – Regulatory Environment," North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. The law gives PEC the option to seek certification, construct a new natural gas plant and retire existing coal units, with resulting reduced emissions, in time to comply with the Clean Smokestacks Act's 2013 emission targets. As discussed in Note 7B on October 22, 2009, the NCUC issued an order granting PEC a certificate of public convenience and necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. PEC projects that the generating facility would be in service by January 2013. On December 1, 2009, PEC filed with the NCUC a plan to retire, no later than December 31, 2017 all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC modified its Clean Smokestacks Act compliance plan to remove retrofitting PEC's Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC totaling $1.1 billion of capital expenditures to meet the Clean Smokestacks Act emission targets. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

O&M expenses increase with the operation of pollution control equipment due to the cost of reagents, additional personnel and general maintenance associated with the pollution control equipment. PEC is allowed to recover the cost of reagents and certain other costs under its fuel clause; all other O&M expenses are currently recoverable through base rates.

Two of PEC's largest coal-fired generating units (the Roxboro No. 4 and Mayo units) impacted by the Clean Smokestacks Act are jointly owned. In 2005, PEC entered into an agreement with the joint owner to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B).

Clean Air Interstate Rule

The CAIR issued by the EPA on March 10, 2005, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR, and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR in 2007.

The air quality controls installed to comply with the requirements of the NOx State Implementation Plan Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and Clean Smokestacks Act, as well as plans to replace a portion of PEC's coal-fired generation with gas-fueled generation, largely address the CAIR requirements for our North Carolina units at PEC. PEF met the 2009 phase I requirements for NOx and anticipates meeting the 2010 phase I requirements of CAIR for NOx and SO_2 with a combination of emission reductions generated by in-service emission control equipment and emission allowances. PEF's CR5 equipment was placed in service on December 2, 2009, and PEF's CR4 equipment is expected to be placed in service in 2010.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, the

D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. This decision leaves the CAIR in effect until such time that it is revised or replaced. The EPA informed the D.C. Court of Appeals that development and finalization of a replacement rule could take approximately two years. The outcome of this matter cannot be predicted.

Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and 2 coal-fired steam turbines (CR1 and CR2) and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was anticipated to be around 2020. PEF is required to advise the FDEP of any developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. Accordingly, PEF has advised the FDEP of an expected shift in the Levy schedule as discussed in "Other Matters – Nuclear – Potential New Construction." We are currently evaluating the impacts of the Levy schedule. We cannot predict the outcome of this matter.

Clean Air Mercury Rule

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that set mercury emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encouraged a cap-and-trade approach to achieving those caps, and a delisting rule that eliminated any requirement to pursue a maximum achievable control technology (MACT) approach for limiting mercury emissions from coal-fired power plants. On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the CAMR. The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a MACT standard consistent with the agency's original listing determination. The three states in which the Utilities operate adopted mercury regulations implementing the CAMR and submitted their state implementation rules to the EPA. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. The outcome of this matter cannot be predicted.

Clean Air Visibility Rule

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas, including national parks and wilderness areas, designated as Class I areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, CR1 and CR2. The reductions associated with BART begin in 2013. As discussed above, on December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units.

The CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of the CAIR could be used by states as a BART substitute to fulfill BART obligations, but the states could require the installation of additional air quality controls if they did not achieve reasonable progress in improving visibility. The D.C. Court of Appeals' December 23, 2008 decision remanding the CAIR maintained its implementation such that CAIR satisfies BART for SO_2 and NOx. Should this determination change as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions for BART-eligible units. We are assessing the potential impact of BART and its implications with respect to our
plans and estimated costs to comply with the CAVR. On December 4, 2007, the FDEP finalized a Regional Haze implementation rule that goes beyond BART by requiring sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. However, the FDEP has not determined the level of additional controls PEF may need to implement. The outcome of these matters cannot be predicted.

Compliance Strategy

Both PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, the CAVR, mercury regulation and related air quality regulations. The air quality controls installed to comply with the requirements of the NOx SIP Call and Clean Smokestacks Act, as well as plans to replace a portion of PEC's coal-fired generation with gas-fueled generation, resulted in a reduction of the costs to meet PEC's CAIR requirements.

PEC has completed installation of controls to meet the NOx SIP Call requirements. The NOx SIP Call is not applicable to sources in Florida. Expenditures for the NOx SIP Call included the cost to install NOx controls under programs by North Carolina and South Carolina to comply with the federal eight-hour ozone standard.

The FPSC approved PEF's petition to develop and implement an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR and for recovery of prudently incurred costs necessary to achieve this strategy through the ECRC (see discussion above regarding the vacating of the CAMR and remanding of the CAIR). PEF's April 1, 2009 filing with the FPSC for true-up of final 2008 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and included an estimated total project cost of approximately $1.2 billion to be spent through 2016, to plan, design, build and install pollution control equipment at the Anclote and Crystal River Plants. As discussed in Note 7C, on August 28, 2009, PEF filed for recovery of costs through the ECRC, and the FPSC approved PEF's filing on November 2, 2009. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed above, or to meet revised compliance requirements of a revised or new implementing rule for the CAIR. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Environmental compliance cost estimates are dependent upon a variety of factors and, as such, are highly uncertain and subject to change. Factors impacting our environmental compliance cost estimates include new and frequently changing laws and regulations; the impact of legal decisions on environmental laws and regulations; changes in the demand for, supply of and costs of labor and materials; changes in the scope and timing of projects; various design, technology and new generation options; and projections of fuel sources, prices, availability and security. Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. We cannot predict the impact that the EPA's further CAIR proceedings will have on our compliance with the CAVR requirements and will continue to reassess our plans and estimated costs to comply with the CAVR. The timing and extent of the costs for future projects will depend upon final compliance strategies.

The following tables contain information about our current estimates of capital expenditures to comply with environmental laws and regulations described above. Amounts presented in the tables exclude AFUDC.

Progress Energy

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
Clean Smokestacks Act [(a)]	2002 – 2013	$1,100	$1,050
In-process CAIR projects [(b)]	2005 – 2010	1,200	1,065
CAVR [(c)]	– 2017	–	–
Mercury regulation [(d)]	2006 – 2017	–	4
Total air quality		2,300	2,119
Clean Water Act Section 316(b) [(e)]		–	–
Total air and water quality		$2,300	$2,119

PEC

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
Clean Smokestacks Act [(a)]	2002 – 2013	$1,100	$1,050
In-process CAIR projects [(b)]	2005 – 2008	–	–
CAVR [(c)]	– 2017	–	–
Mercury regulation [(d)]	2006 – 2017	–	4
Total air quality		1,100	1,054
Clean Water Act Section 316(b) [(e)]		–	–
Total air and water quality		$1,100	$1,054

PEF

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
In-process CAIR projects [(b)]	2005 – 2010	$1,200	$1,065
CAVR [(c)]	– 2017	–	–
Mercury regulation [(d)]		–	–
Total air quality		1,200	1,065
Clean Water Act Section 316(b) [(e)]		–	–
Total air and water quality		$1,200	$1,065

(a) PEC is continuing to evaluate various design, technology and new generation options that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

(b) PEF is continuing construction of its in-process emission control projects. Additional compliance plans for PEC and PEF to meet the requirements of a revised rule will be determined upon finalization of the rule. See discussion under "Clean Air Interstate Rule."

(c) As a result of the decision remanding the CAIR, compliance plans and costs to meet the requirements of the CAVR are being reassessed. See discussion under "Clean Air Visibility Rule."

(d) Compliance plans to meet the requirements of a revised or new implementing rule will be determined upon finalization of the rule. See discussion under "Clean Air Mercury Rule."

(e) Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act will be determined upon finalization of the rule. See discussion under "Water Quality."

All environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, which included projects at PEC's Asheville, Lee, Mayo and Roxboro P lants, have been placed in service. On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. Additional projects requiring material environmental compliance costs may be implemented in the future to meet compliance requirements.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. As a result of changes in the scope of work related to estimation of costs for compliance with the CAIR and the uncertainty regarding the EPA's further CAIR proceedings, the delisting determination and the CAMR discussed above, PEF is currently unable to estimate certain costs of compliance. However, PEF believes that future costs to comply with new or subsequent rule interpretations could be significant. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when those new regulations are finalized.

North Carolina Attorney General Petition under Section 126 of the Clean Air Act

In March 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force fossil fuel-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. In 2006, the EPA issued a final response denying the petition, and the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's denial. In 2009, the D.C. Court of Appeals remanded the EPA's denial to the agency for reconsideration. The outcome of the remand proceeding cannot be predicted.

National Ambient Air Quality Standards

In 2006, the EPA announced changes to the NAAQS for particulate matter. The changes in particulate matter standards did not result in designation of any additional nonattainment areas in PEC's or PEF's service territories. Environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's particulate matter rule does not adequately restrict levels of particulate matter, especially with respect to the annual and secondary standards. On February 24, 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. The outcome of this matter cannot be predicted.

In 2008, the EPA revised the 8-hour primary and secondary standards for the NAAQS for ground-level ozone. Additional nonattainment areas may be designated in PEC's and PEF's service territories as a result of these revised standards. On May 27, 2008, a number of states, environmental groups and industry associations filed petitions against the revised NAAQS in the D.C. Court of Appeals. The EPA requested the D.C. Court of Appeals to suspend proceedings in the case while the EPA evaluates whether to maintain, modify or otherwise reconsider the revised NAAQS. In September 2009, the EPA announced that it is reconsidering the level of the ozone NAAQS. The EPA originally indicated plans to designate nonattainment areas for these standards by March 2010. However, the EPA announced that it will stay those designations until after its reconsideration has been completed.

On January 7, 2010, the EPA announced a proposed revision to the primary ozone NAAQS. In addition, the EPA proposed a cumulative seasonal secondary standard. The EPA plans to finalize the revisions by August 31, 2010, and to designate nonattainment areas by August 2011. The proposed revisions are significantly more stringent than the current NAAQS. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

On January 25, 2010, the EPA announced a revision to the primary NAAQS for nitrogen dioxide. Since 1971, when the first NAAQS were promulgated, the standard for nitrogen dioxide has been an annual average. The EPA has retained the annual standard and added a new 1-hour NAAQS. In conjunction with proposing changes to the standard, the EPA is also requiring an increase in the coverage of the monitoring network, particularly near roadways where the highest concentrations are expected to occur due to traffic emissions. The EPA plans to designate nonattainment areas by January 2012. Currently, there are no monitors reporting violation of the new standard in PEC's or PEF's service territories, but the expanded monitoring network will provide additional data, which could result in additional nonattainment areas. The outcome of this matter cannot be predicted.

On December 8, 2009, the EPA proposed a new 1-hour NAAQS for sulfur dioxide. The current primary NAAQS on a 24-hour average basis and annual average would be eliminated under the proposed rule. A 1-hour standard in the proposed range is a significant increase in the stringency of the standard and it would increase the risk of nonattainment, especially near uncontrolled coal-fired facilities. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants to determine whether changes at those facilities were subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The EPA has undertaken civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements requiring expenditures by these unaffiliated utilities, several of which included reported expenditures in excess of $1.0 billion for retrofit of pollution control equipment. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the unaffiliated utilities may seek recovery of the related costs through rate adjustments or similar mechanisms.

Water Quality

1. General

As a result of the operation of certain pollution control equipment required to comply with the air quality issues outlined above, new sources of wastewater discharge will be generated at certain affected facilities. Integration of these new wastewater discharges into the existing wastewater treatment processes is currently ongoing and will result in permitting, construction and treatment requirements imposed on the Utilities now and into the future. The future costs of complying with these requirements could be material to our or the Utilities' results of operations or financial position.

On September 15, 2009, the EPA announced that it had completed a multi-year study of power plant wastewater discharges and concluded that current regulations have not kept pace with changes in the electric power industry since the regulations were issued in 1982, including addressing impacts to wastewater discharge from operation of air pollution control equipment. As a result, the EPA has announced that it plans to revise the regulations that govern wastewater discharge, which may result in operational changes and additional compliance costs in the future. The outcome of this matter cannot be predicted.

2. Section 316(b) of the Clean Water Act

Section 316(b) of the Clean Water Act (Section 316(b)) requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The EPA promulgated a rule implementing Section 316(b) in respect to existing power plants in July 2004.

A number of states, environmental groups and others sought judicial review of the July 2004 rule. In 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA, and the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitted facilities must meet any requirements under Section 316(b) as determined by the permitting authorities on a case-by-case, best professional judgment basis. Several parties filed petitions for writ of certiorari to the U.S. Supreme Court. On April 1, 2009, the U.S. Supreme Court issued its opinion holding that the EPA, in selecting the "best technology" pursuant to Section 316(b), does have the authority to reject technology when its costs are "wholly disproportionate" to the benefits expected. Also, the U.S. Supreme Court held that EPA's site-specific variance procedure (contained in the July 2004 rule) was permissible in that the procedure required testing to determine whether costs would be "significantly greater than" the benefits before a variance would be considered. As a result of these developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule after it is established by the EPA. Costs of compliance with a revised or new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our cost estimates to comply with the July 2004 rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. As discussed under "Other Matters – Regulatory Environment," on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce GHG emissions as well as a national REPS. The U.S. Senate is considering similar proposals. Final legislation will depend upon changes made during the legislative process to the provisions and the manner in which key provisions are implemented, including for the regulation of carbon. In addition, the Obama administration has begun the process of regulating GHG emissions through use of the Clean Air Act. On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. On December 15, 2009, the EPA announced that six GHGs (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) pose a threat to public health and welfare under the Clean Air Act. A number of parties have filed petitions for review of this finding in the D.C. Court of Appeals. The full impact of final legislation, if enacted, and additional regulation resulting from other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time for which the Utilities would seek corresponding rate recovery. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue.

As discussed under "Other Matters – Regulatory Environment," in 2008 the state of Florida passed comprehensive energy legislation, which includes a directive that the FDEP develop rules to establish a cap-and-trade program to regulate GHG emissions that would be presented to the legislature no earlier than January 2010. The FDEP is currently in the process of studying GHG policy options and the potential economic impacts, but it has not developed a regulation for the consideration of the legislature. As discussed under "Clean Smokestacks Act," on July 31, 2009, the governor of North Carolina signed into law a bill that may impact PEC's Clean Smokestacks Act compliance plans. While state-level study groups have been active in all three of our jurisdictions, we continue to believe that this issue requires a national policy framework – one that provides certainty and consistency. Our balanced solution as discussed in "Other Matters – Energy Demand" is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation.

There are ongoing efforts to reach a new international climate change treaty to succeed the Kyoto Protocol. The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other GHGs. Although the treaty went into effect on February 16, 2005, the United States has not adopted it. In December 2009, the United Nations Framework Convention on Climate Change convened the 15th Conference of the Parties to conduct further negotiations on GHG emissions reductions. At the conclusion of the conference, a number of the parties, including the United States, entered into a nonbinding accord calling upon the parties to submit emission reduction targets for 2020 to the United Nations Framework Convention on Climate Change Secretariat by the end of January 2010. On January 28, 2010, President Obama submitted a proposal to reduce the U.S. GHG emissions in the range of 17 percent below 2005 levels by 2020, subject to future Congressional action.

Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol, potential new international treaties or federal or state proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time.

Prior to 2009, the EPA received waiver requests from a number of states to allow those states to set standards for CO_2 emissions from new vehicles. The EPA denied those requests. On January 26, 2009, the Obama administration requested the EPA to review those denials of waiver requests. On June 30, 2009, the EPA granted California's waiver request, enabling the state to enforce its GHG emissions standards for new motor vehicles, beginning with the current model year. Additional states may set similar standards as a result of the decision. The impact of this development cannot be predicted.

On September 22, 2009, the EPA issued the final GHG emissions reporting rule, which establishes a national protocol for the reporting of annual GHG emissions. Facilities that emit greater than 25,000 metric tons per year of GHGs must report emissions by March 31 of each year beginning in 2011 for year 2010 emissions. Because the rule builds on current emission-reporting requirements, compliance with the requirements is not expected to have a material impact on the Utilities.

SYNTHETIC FUELS TAX CREDITS

Historically, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Internal Revenue Code (the Code) (Section 29) and as redesignated effective 2006 as Section 45K of the Code (Section 45K) as discussed below. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. Qualifying synthetic fuels facilities entitled their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The synthetic fuels tax credit program expired at the end of 2007, and the synthetic fuels businesses were abandoned and reclassified to discontinued operations.

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code effective January 1, 2006. The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit removed the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a one-year carry back period and a 20-year carry forward period.

Total Section 29/45K credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition) were $1.891 billion, of which $1.179 billion has been used through December 31, 2009, to offset regular federal income tax liability and $712 million is being carried forward as deferred tax credits.

See Note 22D and Item 1A, “Risk Factors,” for additional discussion related to our previous synthetic fuels operations.

LEGAL

We are subject to federal, state and local legislation and court orders. The specific issues, the status of the issues, accruals associated with issue resolutions and our associated exposures are discussed in detail in Note 22D.

NEW ACCOUNTING STANDARDS

See Note 2 for a discussion of the impact of new accounting standards.

PEC

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's MD&A of Financial Condition and Results of Operations, insofar as they relate to PEC: "Results of Operations," "Application of Critical Accounting Policies and Estimates," "Liquidity and Capital Resources" and "Other Matters."

The following MD&A and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

PEC has primarily used a combination of debt securities, commercial paper and its revolving credit agreement for liquidity needs in excess of cash provided by operations. PEC also participates in the utility money pool, which allows PEC and PEF to lend and borrow to and from each other.

See discussion of PEC's credit ratings in Progress Energy "Credit Rating Matters."

PEC expects to have sufficient resources to meet its future obligations through a combination of internally generated funds, commercial paper borrowings, money pool borrowings, its credit facility, long-term debt, preferred stock and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

Cash Flows from Operations

In 2009, net cash provided by operating activities increased when compared to 2008. The $222 million increase in operating cash flow was primarily due to a $258 million increase in the recovery of deferred fuel costs due to higher fuel rates in 2009, $67 million in lower net income tax payments and a $63 million decrease in inventory purchases primarily driven by lower coal prices. These impacts were partially offset by $163 million of pension and other benefits contributions made in 2009.

In 2008, net cash provided by operating activities increased when compared to 2007. The $43 million increase in operating cash flow was primarily due to a $79 million increase in cash receipts from a wholesale customer due to the expiration of a prepayment agreement; income tax impacts including $80 million in lower income tax payments; a $57 million increase from accounts payable and payables to affiliates, largely driven by the timing of payments; a $45 million increase from timing of customer collections; and a $32 million increase from net interest payments. These impacts were partially offset by a $119 million decrease in the recovery of fuel costs, largely driven by an under-recovery of fuels costs in 2008, and a $109 million increase in inventory purchases, primarily coal, driven by higher prices.

Investing Activities

In 2009, net cash used by investing activities increased $121 million when compared with 2008. The increase was primarily due to a $94 million increase in advances to affiliated companies and a $79 million increase in gross property additions, partially offset by a $57 million decrease in nuclear fuel additions. Property additions are primarily for normal construction activity and ongoing capital expenditures related to environmental compliance programs.

In 2008, net cash used by investing activities increased $150 million when compared with 2007. The increase was primarily due to a $79 million increase from changes in advances to affiliated companies and a $75 million decrease in net proceeds from available-for-sale securities and other investments. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts.

Financing Activities

Net cash used by financing activities increased $77 million for 2009 when compared to 2008. The increase in net cash used by financing activities was primarily due to the $200 million in dividends paid to the Parent in 2009, the $110 million net repayment of commercial paper in 2009, the $110 million issuance of commercial paper in 2008 and the $100 million increase in the payment at maturity of long-term debt in 2009 compared to 2008. These impacts were partially offset by a $273 million increase in the proceeds from the issuance of long-term debt in 2009 compared to 2008, as well as the $154 million repayment of advances from affiliates in 2008.

Net cash used by financing activities decreased $146 million for 2008 when compared to 2007. The decrease in net cash used by financing activities was primarily due to $322 million in net proceeds from the issuance of long-term debt in 2008, $143 million in dividends paid to the Parent in 2007, and outstanding commercial paper issuances of $110 million, offset by a $308 million change in advances from affiliated companies and a $100 million increase in the retirement of long-term debt.

On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC’s $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC’s outstanding money pool balance and for general corporate purposes.

On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.

On March 12, 2008, PEC amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on March 28, 2008. PEC’s RCA is now scheduled to expire on June 28, 2011.

On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC’s $300 million 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.

On November 18, 2008, PEC; the Parent, as a well-known seasoned issuer; and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued. (See “Credit Facilities and Registration Statements.”)

On August 15, 2007, due to extreme volatility in the commercial paper market, PEC borrowed $300 million under its $450 million RCA and paid at maturity $200 million of its 6.80% First Mortgage Bonds. On September 17, 2007, PEC used $150 million of available cash on hand to repay a portion of the amount borrowed under the RCA. On October 17, 2007, PEC repaid the remaining $150 million of its RCA loan using available cash on hand.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC’s estimated capital requirements for 2010, 2011 and 2012 are approximately $1.5 billion to $1.6 billion, $1.6 billion and $1.4 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation and upgrade existing facilities as discussed in Progress Energy “Capital Expenditures.”

PEC expects to fund its capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contributions of equity from the Parent. In addition, PEC has a $450 million credit facility that supports the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEC’s working capital requirements.

Over the long term, meeting the anticipated load growth will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generation facilities in the Carolinas toward the end of the next decade. This approach will require PEC to make significant capital investments. See Progress Energy “Introduction – Strategy” for additional information. PEC may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

PEC has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

CAPITALIZATION RATIOS

The following table shows PEC’s capitalization ratios at December 31:

	2009	2008
Common stock equity	**55.2%**	53.8%
Preferred stock	**0.7%**	0.8%
Total debt	**44.1%**	45.4%

See the discussion of PEC’s future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 11 for further information regarding PEC’s debt and credit facility.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See discussion under Progress Energy, “Contractual Obligations” below, and Notes 22A, 22B and 22C for information on PEC’s off-balance sheet arrangements and contractual obligations at December 31, 2009.

GUARANTEES

See discussion under Progress Energy and Note 22C for a discussion of PEC’s guarantees.

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEC may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

PEC is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. In most cases, these contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts in the following table are estimates and therefore will likely differ from actual purchase amounts. Further disclosure regarding PEC’s contractual obligations is included in the respective notes to the PEC Consolidated Financial Statements. PEC takes into consideration the future commitments when assessing its liquidity and future financing needs.

The following table reflects PEC's contractual cash obligations and other commercial commitments at December 31, 2009, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt [a] (See Note 11)	$ 3,715	$ 6	$ 500	$ 400	$ 2,809
Interest payments on long-term debt [b]	2,041	180	361	275	1,225
Capital lease obligations (See Note 22B)	16	2	4	10	–
Operating leases [c] (See Note 22B)	800	25	41	96	638
Fuel and purchased power [d] (See Note 22A)	9,823	1,445	2,374	1,946	4,058
Other purchase obligations (See Note 22A)	630	381	213	30	6
Minimum pension funding requirements [e]	573	55	255	164	99
Other postretirement benefits [f] (See Note 16A)	200	15	34	39	112
Uncertain tax positions [g] (See Note 14)	–	–	–	–	–
Other commitments [h]	105	13	26	26	40
Total	$ 17,903	$ 2,122	$ 3,808	$ 2,986	$ 8,987

[a] PEC's maturing debt obligations are generally expected to be repaid with cash from operations or refinanced with new debt issuances in the capital markets.

[b] Interest payments on long-term debt are based on the interest rate effective at December 31, 2009.

[c] Amounts include certain related executory cost commitments.

[d] Fuel and purchased power commitments represent the majority of PEC's remaining future commitments after its debt obligations. Essentially all of PEC's fuel and certain purchased power costs are recovered through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support.

[e] Represents the projected minimum required contributions to the qualified pension trusts for a total of 10 years. These amounts are subject to change significantly based on factors such as pension asset earnings and market interest rates.

[f] Represents projected benefit payments for a total of 10 years related to PEC's postretirement health and life plans. These amounts are subject to change based on factors such as experienced claims and general health care cost trends.

[g] Uncertain tax positions of $59 million are not reflected in this table as PEC cannot predict when open income tax years will be closed with completed examinations. It is reasonably possible that the total amounts of PEC's unrecognized tax benefits will decrease by up to approximately $10 million during the 12-month period ending December 31, 2010, due to expected settlements.

[h] By NCUC order, in 2008, PEC began transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of the original $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

PEF

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's MD&A of Financial Condition and Results of Operations, insofar as they relate to PEF: "Results of Operations," "Application of Critical Accounting Policies and Estimates," "Liquidity and Capital Resources" and "Other Matters."

The following MD&A and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "Safe Harbor for Forward-Looking Statements" and Item 1A, "Risk Factors," for a discussion of the factors that may impact any such forward-looking statements made herein.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

PEF has primarily used a combination of debt securities, equity contributions from the Parent, commercial paper and its revolving credit agreement for liquidity needs in excess of cash provided by operations. PEF also participates in the utility money pool, which allows PEC and PEF to lend and borrow to and from each other.

See discussion of PEF's credit ratings in Progress Energy "Credit Rating Matters."

PEF expects to have sufficient resources to meet its future obligations through a combination of internally generated funds, commercial paper borrowings, money pool borrowings, its credit facility, long-term debt, preferred stock and/or contributions of equity from the Parent.

CASH FLOW DISCUSSION

HISTORICAL FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

Cash Flows from Operations

Net cash provided by operating activities for 2009 increased when compared with 2008. The $1.086 billion increase in operating cash flow was primarily due to a $365 million increase in the recovery of deferred fuel costs due to higher fuel rates; a $323 million payment made in 2008 to counterparties for collateral associated with derivative contracts and $190 million net refunds of cash collateral in 2009. See discussion of PEF's fuel cost recovery in Progress Energy "Future Liquidity and Capital Resources." The change in derivative collateral assets was primarily driven by the relative fair values of our commodity derivative instruments (See Note 17A).

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $748 million decrease in operating cash flow was primarily due to a $331 million decrease in the recovery of fuel costs driven by the under-recovery of higher fuels costs in 2008; $323 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $47 million in net refunds of cash collateral in 2007; and an $87 million increase in inventory purchases, primarily driven by coal price increases and an increase in emission allowances purchases. See discussion of PEF's fuel cost recovery in Progress Energy "Future Liquidity and Capital Resources." The change in derivative collateral assets was primarily driven by the relative fair values of our commodity derivative instruments (See Note 17A).

Investing Activities

In 2009, net cash used by investing activities increased $89 million when compared with 2008. The increase in cash used by investing activities was primarily due to a $149 million decrease in settlements of advances to affiliates and a $35 million increase in nuclear fuel additions, partially offset by a $103 million decrease in property additions. The decrease in property additions was driven by decreases in environmental compliance spending and completion of the Bartow Plant repowering project, partially offset by an increase in expenditures for nuclear projects.

In 2008, net cash used by investing activities increased $37 million when compared with 2007. The increase in cash used by investing activities was primarily due to a $338 million increase in capital expenditures for utility property additions, partially offset by a $298 million decrease from changes in advances to affiliated companies. The increase in capital expenditures for utility property additions was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow Plant to more efficient natural gas-burning technology and a $52 million decrease related to the Hines 4 facility, which was placed in service in 2007.

Financing Activities

Net cash provided by financing activities decreased $995 million for 2009 when compared to 2008. The decrease in cash provided by financing activities was primarily due to PEF's $1.475 billion in net proceeds from issuance of long-term debt in 2008, outstanding commercial paper issuances of $371 million in 2008, and repayment of commercial paper outstanding of $371 million in 2009, partially offset by receipts of $620 million in contributions from the Parent in 2009 and $532 million long-term debt retirements in 2008.

Net cash provided by financing activities increased $781 million for 2008 when compared to 2007. The increase in cash provided by financing activities was primarily due to PEF's $1.475 billion in net proceeds from issuance of long-term debt and outstanding commercial paper issuances of $371 million in 2008, partially offset by $739 million in net proceeds from the issuance of $750 million of long-term debt in 2007 and a $443 million increase in long-term debt retirements.

In 2009, PEF did not issue or retire long-term debt.

On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.

On March 12, 2008, PEF amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on March 28, 2008. PEF's RCA is now scheduled to expire on March 28, 2011.

On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.

On November 18, 2008, PEF; the Parent, as a well-known seasoned issuer; and PEC filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued. (See "Credit Facilities and Registration Statements.")

On July 2, 2007, PEF paid at maturity $85 million of its 6.81% Medium-Term Notes with available cash on hand and commercial paper borrowings. On September 18, 2007, PEF issued $500 million of First Mortgage Bonds, 6.35% Series due 2037 and $250 million of First Mortgage Bonds, 5.80% Series due 2017. The proceeds were used to repay PEF's utility money pool borrowings and the remainder was placed in temporary investments for general corporate use as needed.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEF's estimated capital requirements for 2010, 2011 and 2012 are approximately $0.9 billion to $1.0 billion, $0.9 billion and $0.7 billion, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and add environmental control facilities as discussed in Progress Energy "Capital Expenditures." PEF's estimated capital requirements include potential nuclear construction expenditures for Levy. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. Because of anticipated schedule shifts, we anticipate amending the EPC agreement (See discussion in Progress Energy "Other Matters – Nuclear – Potential New Construction"), and the forecasted capital expenditures reflect the anticipated impact of such amendment. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time, and, accordingly, are not included in forecasted capital expenditures. Potential nuclear construction expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions. Forecasted potential nuclear construction expenditures for 2010, 2011 and 2012 include approximately $70 million, $30 million and $30 million, respectively, of preconstruction expenditures, which are eligible for recovery under Florida's nuclear cost-recovery rule.

PEF expects to fund its capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contributions of equity from the Parent. In addition, PEF has a $450 million credit facility that supports the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEF's working capital requirements.

At December 31, 2009, the current portion of PEF's long-term debt was $300 million, which we expect to fund with long-term debt issued in 2010.

Over the long term, meeting the anticipated load growth will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generation facilities in Florida. This approach will require PEF to make significant capital investments. PEF may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

PEF has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

CAPITALIZATION RATIOS

The following table shows PEF's capitalization ratios at December 31:

	2009	2008
Common stock equity	**49.1%**	41.1%
Preferred stock	**0.4%**	0.4%
Total debt	**50.5%**	58.5%

See the discussion of PEF's future liquidity and capital resources, including financial market impacts, under Progress Energy and see Note 11 for further information regarding PEF's debt and credit facility.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See discussion under Progress Energy and Notes 22A, 22B and 22C for information on PEF's off-balance sheet arrangements and contractual obligations at December 31, 2009.

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEF may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.